



Report on Wholesale Electric Generation Investigation

September 2002

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Executive Summary

The California Public Utilities Commission (CPUC) obtained and analyzed data on power production, power plant outages, bidding behavior of electricity generators and electricity transmission during the 38 blackout and service interruption days in California occurring from November 2000 through May 2001. This report analyzes the operations, bids and production and transmission of electricity on the 38 blackout and service interruption days of the five largest non-utility electricity generators – Duke, Dynegy, Mirant and Reliant and AES/Williams. Based on an hour-by-hour and plant-by-plant analysis of this data, this report concludes that most of California’s power blackouts and service interruptions need not have occurred.

Between November 1, 2000 and May 31, 2001, California’s electricity customers experienced power blackouts and service interruptions on 38 days. Blackouts and service interruptions during this energy crisis disrupted commerce and compromised public safety, affecting roughly one-third of all Californians. Certain large commercial and industrial customers who had agreed to limited service interruptions in exchange for lower rates (“non-firm” customers) had to shut down operations much more frequently than was necessary or anticipated, often day after day.

If the state’s five largest independent electricity generators had operated all of their available capacity from November 2000 through May 2001 (the height of California’s energy crisis), California’s citizens could have avoided:

- **All 4 days of blackouts in Southern California;**
- **65% of the blackout hours in Northern California;**
- **81% of service interruption hours in the South, and 51% of service interruption hours in the North;**

This report also finds:

- **On all but 2 of the 32 statewide blackout and service interruption days shown, the five biggest independent electricity generators did not supply well over 500 megawatts of power that they could have generated.**

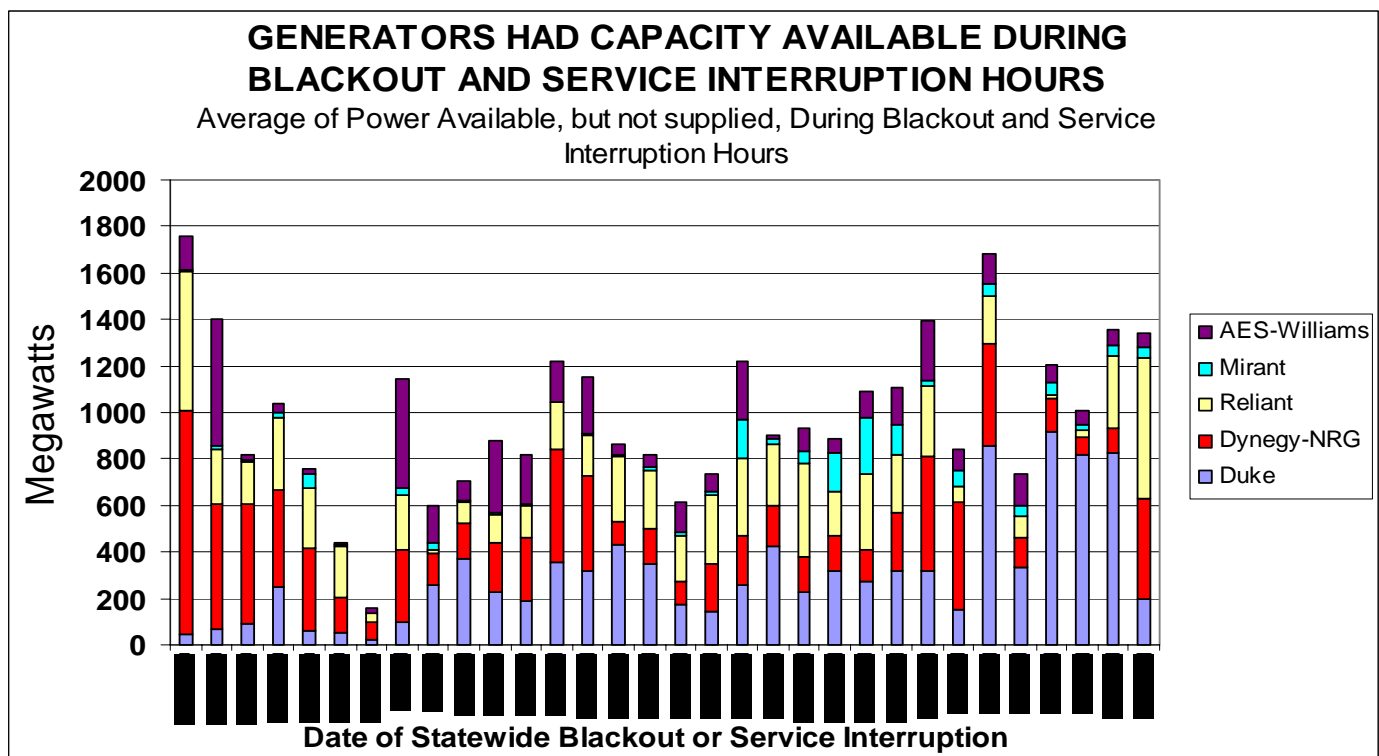
Sufficient generating capacity for California’s families and businesses existed, but blackouts and service interruptions occurred, because generators, Duke, Dynegy, Mirant, Reliant and AES/Williams, did not produce needed power even though their plants could have met California’s electricity needs. This report reaches these conclusions by treating as valid every plant outage reported by any generator, even though reported plant outages were well above historical averages during this period. The CPUC’s investigation of reported outages remains ongoing and is not the subject of this report.

This report treats as “available power” during a particular hour only power that was available according to data from the California Independent System Operator (ISO). The ISO’s data was based on reports submitted by the generators themselves. Our analysis gives the generators the benefit of the doubt in several ways, chiefly by accepting generator claims of plant outages and mechanical problems at face value, and giving full credit for their out-of-market sales.

The Generators Did Not Produce All Available Power on Blackout and Service Interruption Days

As Figure A shows, during blackout and service interruption hours, the five wholesale electricity generators did not produce power from all available generation capacity.

Figure A



This report also examines the behavior of each of the five generators on each of the blackout and service interruption days during the crisis. When the generators' own data on plant outages is added to the data on power not generated, as summarized in the graph above, the combined data shows that between 37% and 46% of the total generating capacity of the five generators was either not available, or not supplied, on the 32 statewide blackout and service interruption days that are the focus of this Report. Specifically,

- **37% of Dynegy's capacity was either out of service or not made available;**
- **38% of Duke's capacity was either out of service or not made available;**
- **42% of Reliant's capacity was either out of service or not made available;**
- **42% of Mirant's capacity was either out of service or not made available; and**
- **46% of Williams/AES's capacity was either out of service or not made available.**

During all of the statewide blackouts and service interruptions, the five generators also failed to bid all available power into the ISO's markets.

Had the generators produced the power they had available, most of the statewide blackouts and service interruptions could have been avoided without overloading the transmission lines linking Northern and Southern California. As is shown in Figures B and C, for firm-service customers, all of the blackouts in Southern California and 65% of the blackouts in Northern California could have been avoided. For interruptible customers, 82% of interruption hours in Southern California; and 51% of interruption hours in Northern California could have been avoided.

It is important to note that this report makes no finding that any of the blackouts or service interruptions was unavoidable. The analysis merely establishes that Californians need not have experienced the large majority of blackouts and service interruptions in 2000 – 2001.

Figure B

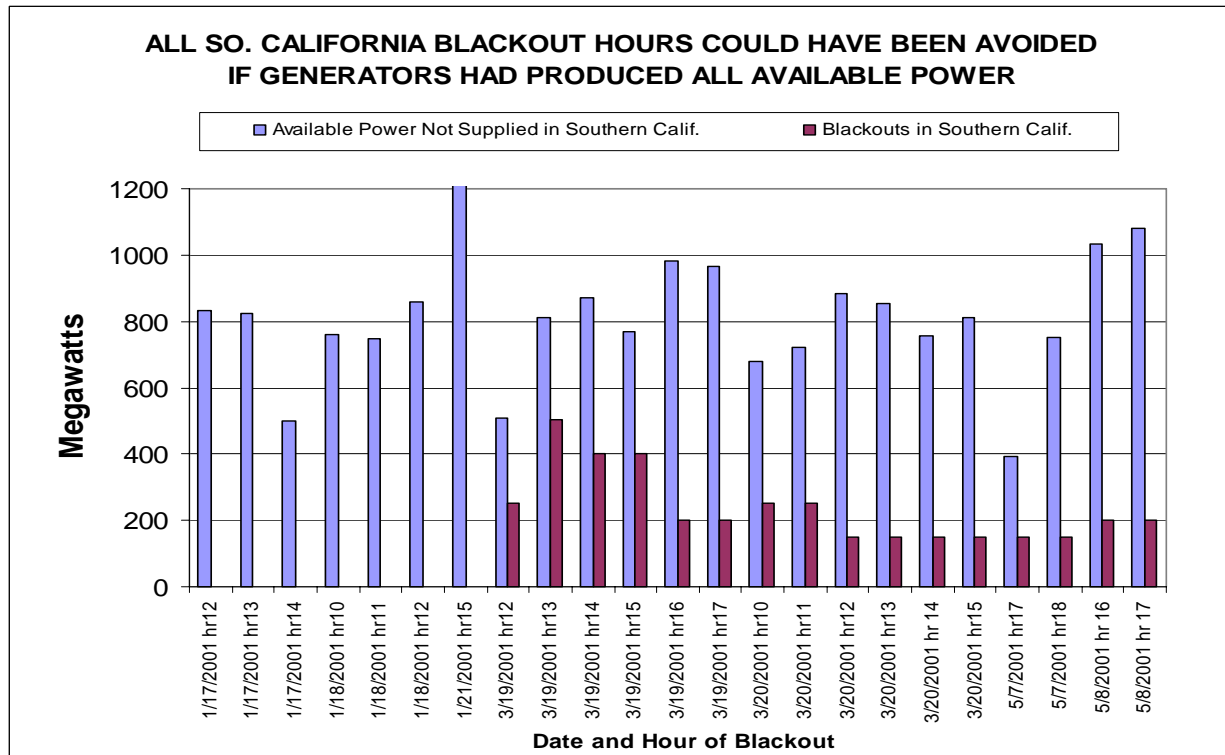
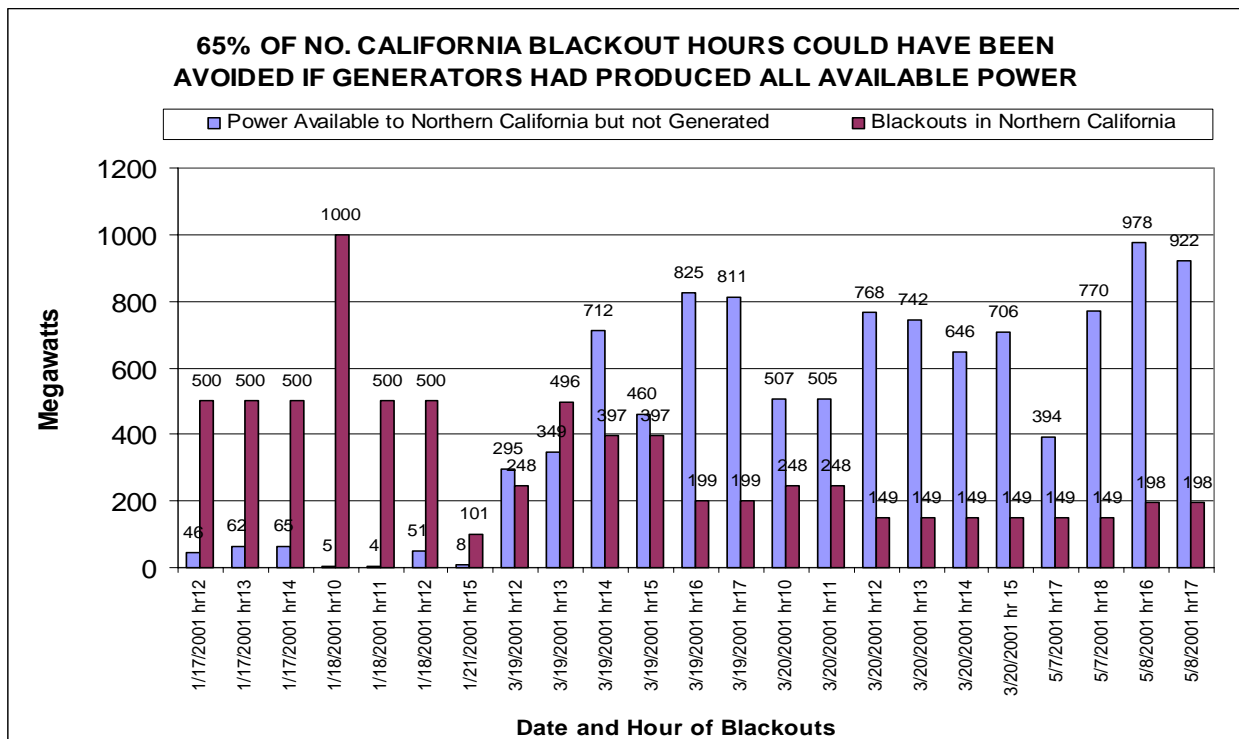


Figure C



Throughout the crisis, the ISO was declaring emergencies on an almost daily basis and urgently seeking all available power, making it obvious that wholesale electricity generators should have bid in, or otherwise provided, every last megawatt of power in order to help alleviate the crisis. There are a number of possible reasons why a given generator did not generate power on a given blackout or service interruption day. For example, the ISO may not have used all available bids, the generator may not have followed ISO instructions, or, occasionally, local power lines may have been full. None of these reasons provides a justification for the generators' failure to bid in all available power on a blackout or service interruption day.

Even accepting the generators' claims regarding plant outages and mechanical problems as valid, the rate of plant outages during the energy crisis was well above historical averages. For example, well over 40% of the capacity of Mirant, Reliant and Williams/AES was either not available or not used to meet California's energy needs during blackouts and service interruptions.

Beyond failing to bid all available power into real-time markets, generators withheld power using several other strategies. At various times generators:

- **Failed to follow or delayed their responses to ISO requests to produce power;**
- **Declined the ISO's automated dispatch instructions;**
- **Failed to take all actions necessary to make plants available as soon as possible after plant outages; and**
- **Failed to provide adequate fuel and staffing for plants.**

Preventing Future Artificial Electricity Shortages

Reforms are needed to assure that in the future, the generators cannot create artificial power shortages and market distortions like those of the 2000-2001 energy crisis.

California Legislative Action

California has enacted several of the needed reforms that are within the State's authority. For example, Senate Bill 39 of the Second Extraordinary Session, Statutes of 2002, Chapter 19 (SB 39XX), will help alleviate potential future power shortages by allowing the state to:

- **Monitor the generators to detect unnecessary outages as they occur.**
- **Regulate the generators' planned power plant shutdowns.**
- **Review the legitimacy of the generators' unplanned shutdowns.**
- **Penalize generators and scheduling coordinators who violate the new regulations.**

Since the adoption of SB 39XX, the ISO and the CPUC are developing procedures for scheduling outages and evaluating power plant performance. Armed with the new authority provided by SB 39XX, the CPUC and the ISO will develop maintenance and operations standards by the end of 2002, and the CPUC will deploy a monitoring and enforcement program.

However, further legislative action may prove necessary to protect Californians from future power shortages. Specifically, if conditions warrant, the California Legislature could modify or repeal Public Utilities Code Section 216(g), which provides that the generators are not treated as public utilities under state law solely by virtue of their ownership or operation of wholesale electrical generation facilities. This reform would make it possible for California to assure that generators are not able to withhold power in the future.

FERC Action

The Federal Energy Regulatory Commission (FERC) should adopt important additional reforms. These include reforms of the ISO tariffs and procedures that are currently proposed to FERC. In an Order issued on July 17, 2002, FERC partially addressed these issues, but FERC's action is not sufficient to safeguard consumers from generator manipulation that could result in unjust and unreasonable electricity prices. The following reforms are necessary:

- **FERC must revoke its enormous and unjustifiable recent increase in the price caps for California electricity (from \$92 per megawatt to \$250 per megawatt).**

- **The ISO's market operations and bidding rules must be redesigned to reduce gaming and market manipulation and prohibit deceptive bidding and power scheduling.**
- **FERC must protect California's and the states' crucial role in regulating electric utilities and transmission organizations like the ISO, in protecting consumers from unjust and unreasonable rates, and in planning their electricity future.**

Chapter 1

From November 2000 Through May 2001, California's Electric System Faced an Unprecedented Crisis

This report sets forth the conclusions of the CPUC staff in its investigation of the five generators'¹ conduct during the energy crisis between November 2000 and May 2001. The CPUC staff and its consultants have reviewed many thousands of pages of documents and electronic records from the generators themselves, the ISO, and the California Power Exchange Corporation (PX). The staff has also received information from the California Department of Water Resources (DWR), which took over primary responsibility for purchasing electricity for California's principal investor-owned electric utilities during the height of the energy crisis.²

**The five generators
analyzed in this report:**

Duke

Dynegy

Mirant

Reliant

Williams/AES

The Five Generators' Role in Meeting Peak Electricity Demand

The five generators own and/or operate power plants throughout the state that were formerly owned by the state's three major investor-owned electric utilities, Pacific Gas &

¹ The wholesale electricity generators and their power-scheduling coordinators (which are either corporate affiliates of the generators or separate companies that market generators' production), include: Duke Energy North America, LLC (Duke), Dynegy Power Marketing, Inc. (Dynegy), Mirant Americas Energy Marketing, LP (Mirant), Reliant Power Generation, Inc. (Reliant), and AES Corporation/Williams Energy Marketing and Trading Company (Williams/AES). In some cases, scheduling coordinators may have sold or reassigned power to other scheduling coordinators or traders than those named above.

² This study examines all natural gas or oil-fueled power plants that had over 50 megawatts of capacity and controlled by the five generators that owned or operated over 1,000 megawatts of such capacity during the study period. The CPUC staff limited this study to the larger plants owned or operated by the five largest suppliers, because those entities had the strongest incentives to withhold capacity in order to raise prices (see Chapter 5 of this report). The largest independent generator not included in the study, Calpine, had the capacity to produce 1,041 megawatts with its plants having capacities of 50 megawatts or more, including 417 megawatts of gas-fired cogeneration, and 624 megawatts of geothermal capacity. Our investigation of Calpine is ongoing.

Electric Company, Southern California Edison Company and San Diego Gas & Electric Company (“the utilities”), but which were sold by the utilities in the late 1990s pursuant to CPUC orders³ issued under AB 1890,⁴ the law that deregulated California’s electric-power market.

The five generators were responsible for approximately 38% (nearly 17,000 megawatts) of the generation capacity in the part of California supplied through the ISO, a system with a total capacity of approximately 45,000 megawatts⁵ during the time period this report covers. The five generators’ plants were crucial to maintaining system reliability, especially on blackout and service interruption days when electricity supplies are very tight.

Blackouts and Service Interruptions and Their Effects on California

During the energy crisis of 2000-2001, blackouts disrupted commerce, jeopardized public safety and directly affected approximately one-third of all Californians served by the three major investor-owned utilities. Based on data obtained from the utilities, approximately 50% of PG&E’s firm customers were blacked out in Northern California, and approximately 15% and 20%, respectively, of the customers of SCE and SDG&E were blacked out in Southern California.

Blackouts occur when service is cut to all customers in a specific geographic area.

Service interruptions occur when power is cut only to “non-firm” customers (those who have agreed to limited power interruptions in exchange for lower rates).

This report provides data on the 38 days on which blackouts and service interruptions occurred and analyzes each hour of blackout and service interruption on those days.

³ See CPUC Decisions D.97-12-107 (PG&E coastal fossil plants); D.97-12-106 (SCE all fossil plants); D.98-10-055 (SDG&E all fossil plants) and D.99-04-026 (PG&E Bay Area fossil plants and geothermal).

⁴ Chapter 854, Statutes of 1996.

⁵ Most of the rest of the installed capacity (approximately 25,000 megawatts) is utility-retained generation (URG), which includes generating facilities owned by the utilities as well as various utility contracts with “qualifying facilities” (independent generators who sell their power directly to the utilities). Approximately 3,000 megawatts of the 45,000 megawatts of generation capacity available to the ISO during the period analyzed was controlled by municipal utilities.

Service interruptions to “non-firm” (large commercial and industrial) customers required those customers to shut down their operations at a far higher rate than was expected.⁶ Other states lured California business with promises of reliable power. Firm-customer blackouts disrupted public safety in many ways. During the winter of 2000-2001, the blackouts and service interruptions put unwarranted pressure on public officials to implement crash programs to build peaking capacity by the following summer. Blackouts and service interruptions required public officials to sign long-term contracts with power generators at exorbitant prices.

A brief history of the energy crisis, provided in the adjacent text box, provides a context for the following discussion.

Timeline of Energy Crisis 2000 – 2001

- ◆ **September 24, 1996** – Enactment of electric restructuring legislation, AB 1890
- ◆ **March 31, 1998** – ISO and PX markets open
- ◆ **August 27, 1999** – First electricity price spike
- ◆ **May 2000** – Beginning of sustained rise in electric prices
- ◆ **June 14, 2000** – Blackout of firm power in the San Francisco Bay Area (the first since WW II)
- ◆ **November 1, 2000** – FERC proposes removal of hard price cap of \$250 per megawatt
- ◆ **November 13, 2000** – First of 38 off-peak season service interruption days
- ◆ **December 8, 2000** – FERC removes “hard cap” on wholesale electricity prices; prices rise further
- ◆ **December 14, 2000** – U.S. Department of Energy orders generators to provide power at ISO request; this requirement expires on February 6, 2001
- ◆ **January 17, 18, and 21, 2001** – Blackouts of firm customers in Northern California
- ◆ **January 18, 2001** – DWR begins to buy power to meet ISO requirements
- ◆ **March 19 & 20, May 7 & 8, 2001** – Blackouts of firm customers in Northern and Southern California
- ◆ **June 19, 2001** – FERC orders generators to bid all available power at a price of no more than \$92 per megawatt; prices fall and power outages virtually end

⁶ Blackouts and service interruptions are necessary when demand (including a reserve) threatens to exceed supply. When this occurs, the ISO, operator of most of California’s electric transmission system, must interrupt some customers’ power supply (*i.e.*, it must shed load to reduce demand) to bring the system back into balance. If this is not done, and there are sudden failures of generation or transmission facilities (or, if demand exceeds supply), the resulting imbalance could cause uncontrolled blackouts and equipment damage throughout the Western grid. “Non-firm” customers are those customers, primarily large businesses, who have volunteered to have their power supply interrupted during power emergencies in exchange for lower rates. “Firm” customers are all other customers, including most households, who have not volunteered to have their power supply interrupted. “Service interruptions” (as that term is used throughout this report) occur when the ISO orders that power be cut only to “non-firm” customers. “Blackouts” (as that term is used throughout this report) occur when the ISO orders that power be cut to both “firm” and “non-firm” customers in a specific geographic area.

Between November 1, 2000 and May 31, 2001, the study period covered by this report, the ISO ordered service interruptions on 38 separate days;⁷ on seven of these days,⁸ the ISO also ordered blackouts of firm customers. These blackouts and service interruptions occurred during the time of year when electricity demand in California is typically well below peak-demand levels, which normally occur on hot summer days when air conditioning loads are heavy. These blackouts and service interruptions were unprecedented in their scope and number. There were blackouts on seven days during the period covered by this report: January 17, January 18, January 21, March 19, March 20, May 7 and May 8, 2001. Northern California experienced blackouts on all seven of these days; Southern California experienced blackouts only on the four days in March and May. California had never experienced a similar circumstance in which the reliability of its electricity system was so seriously compromised for such an extended period of time.

In addition to the numerous blackout and service interruption days, the ISO was forced to declare 82 Stage 2 and 39 Stage 3 emergencies⁹ during the period between November 2000 and May 2001. Even if no power blackout or service interruption occurred on a given day, the existence of a Stage 2 emergency on that day indicated a substantial tightening of power supplies. A Stage 3 emergency indicated even tighter supplies. In the previous 2½ years of ISO operation, only one Stage 2 emergency occurred during the November-to-May period. The Stage 3 emergencies were the first ever.

⁷ Of the 38 days of blackouts and service interruptions, this report focuses on the 32 days in which blackouts or service interruptions affected both Northern and Southern California, because on those days, additional generation from any or all of the five generators would have helped reduce or avoid blackouts and service interruptions. However, this report also studies another six days, including five days when blackouts and service interruptions affected only Northern California, and one day where service interruptions affected only Southern California. The conclusions drawn below about statewide blackout or service interruption days generally apply to non-statewide days as well. Appendices A, B and C show in detail, hour-by-hour, which blackouts and service interruptions could have been avoided had generators utilized all available capacity for all 38 days covered by this study. We exclude from this report two days, December 12, 2000 and February 9, 2001, when the ISO interrupted power only to pumps belonging to the California's Department of Water Resources.

⁸ There was one blackout several months before the period of time covered by this report. On June 14, 2000, the ISO ordered the interruption of 100 megawatts of firm load in the San Francisco Bay Area, due in part to local conditions on the transmission system. Since there was no shortage of capacity statewide on that day, but only problems in moving power to the Bay Area, the ISO did not declare a Stage 3 emergency. This June 14, 2000 event was the first California blackout in living memory caused by factors other than natural causes such as storms or earthquakes.

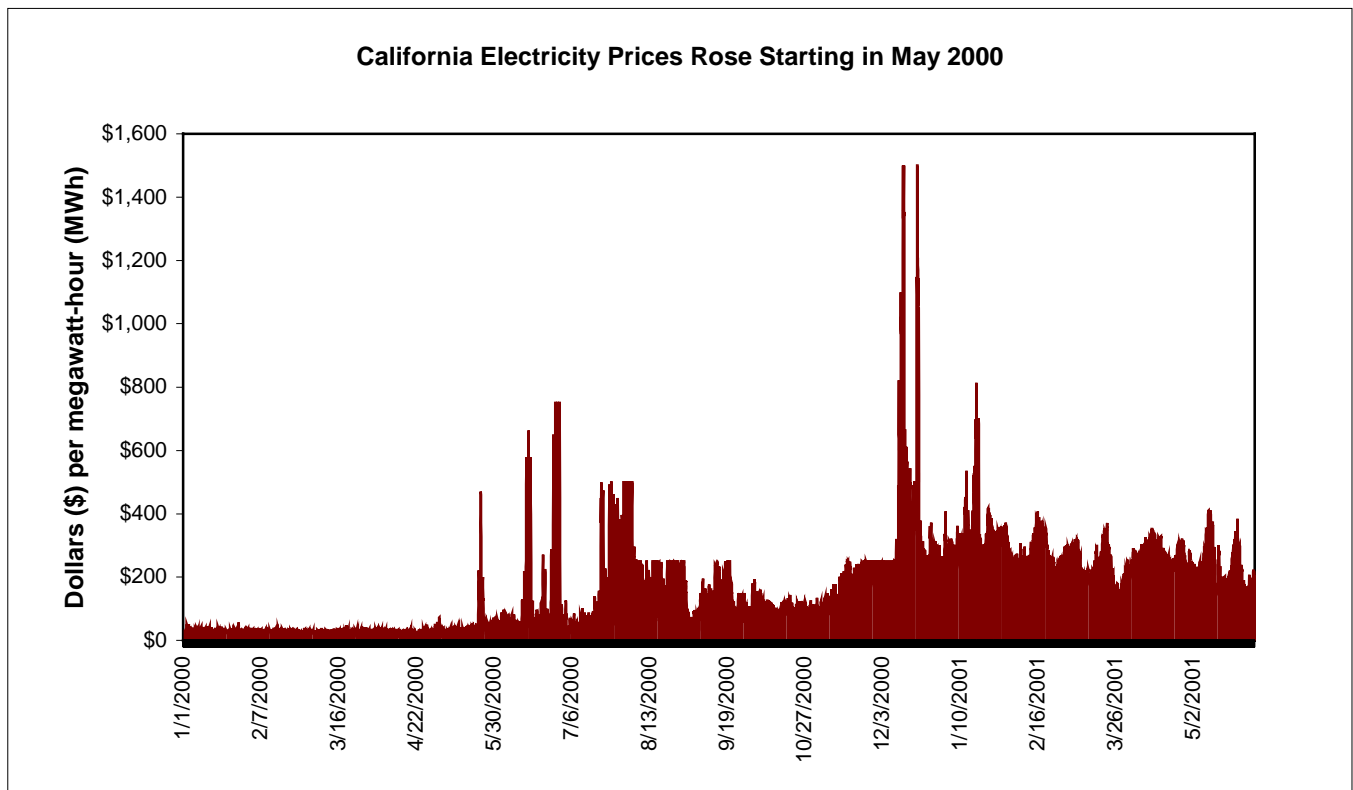
⁹ The ISO declares a Stage 2 emergency for those hours when it anticipates that reserve margins on the system will fall below 5%. The ISO declares a Stage 3 emergency for those hours when it anticipates that reserve margins on the system will fall below roughly 2%.

Electricity Prices Skyrocketed During the Crisis

During this extended crisis, as California's electricity customers were subjected to unexpected blackouts and service interruptions, electricity prices skyrocketed. Before the crisis began in May of 2000, wholesale electricity prices in California consistently averaged \$25 to \$40 per megawatt-hour. In December of 2000, at the height of the crisis, prices rose as high as \$1,500 per megawatt-hour. This was a fifty-fold increase over the steady prices that had prevailed from the beginning of deregulation in the spring of 1998 to the beginning of the crisis. This spike in electricity prices is demonstrated in **Figure 1** below.

Figure 1

Source: California PX & Dept. of Water Resources



Although an increase in the price of natural gas contributed to the rise in electricity prices, natural gas prices did not increase in tandem with electricity prices, and the rise in gas prices was only one of many factors that contributed to the unconscionable, unjust and unreasonable electricity price spikes that California experienced during the energy

crisis.¹⁰ Other factors, including withholding by the generators, have been explored in various studies of the California electricity market. These studies are discussed in more detail in Chapter 5 of this report.

¹⁰ Natural gas prices were also likely manipulated. The FERC is now investigating whether natural gas prices were manipulated, as well as whether natural gas pipeline owners drove prices up illegally. The CPUC has filed a complaint at FERC seeking restitution in connection with this activity that illegally drove up gas prices. See FERC Docket RP00-241-000.

Chapter 2

Report Methodology

To date, no study has addressed the question whether any correlation exists between the blackouts and service interruptions and the five generators' bidding and generating patterns during the crisis.¹¹ This report answers that question.

Because of the significance of that answer, the analysis underlying this report gives the generators the benefit of the doubt in many ways, chiefly: (1) by accepting as genuine the generators' claims of plant outages and mechanical problems, and (2) by giving full credit for out-of-market sales, even though some of these actually were almost certainly offered to the ISO at the last minute and at high prices.

We have not replicated the economic tests used in other published studies for an important reason. As we discuss below, the generators should have offered all of their available power supplies to the ISO at all times. Indeed, after FERC imposed comprehensive market controls in June 2001, including a price cap, trading barriers to prevent some types of market manipulation and a "must-offer" obligation, blackouts and service interruptions nearly ceased even though California's power demand was at its highest in the summer. Also significant were orders of the U.S. Department of Energy (DOE) that required generators to provide power pursuant to nightly requests from the ISO.¹²

This study uses ISO data to trace the actual behavior of the five generators in the California market, identifying power that was available but was either not generated or not offered to the market during blackout and service interruption hours. Unlike previous studies, we have accounted on an hour-by-hour basis for plants taken out of service by their owners, as well as for the five generators' offers to provide capacity to the ISO that the ISO accepted.

¹¹ These studies are summarized in Chapter 5 of this Report.

¹² Orders Pursuant to Section 202 (c) of the Federal Power Act, issued December 14, 20, 27, 2000 and January 5, 11, 17, and 23, 2001. The DOE Orders specified that every night, the ISO should inform generators about its power needs for the following day. The generators were supposed to respond to the ISO's power requests by the following morning. The DOE orders were in effect from December 14, 2000 through February 6, 2001.

CPUC staff has reviewed thousands of documents and electronic data records from the generators themselves, the ISO, and the PX. Staff has also received additional documentation from DWR, which took over primary responsibility for the purchase of electricity on behalf of California's main investor-owner electric utilities on January 8, 2001, during the height of the energy crisis, pursuant to ABX1 1 (Chapter 4, Statutes of 2001).

The method used to determine how much available power the five generators did not generate gives the five generators the benefit of the doubt in several ways, chiefly by accepting the generators' claims of plant outages and mechanical problems at face value. This method gives the five generators additional benefits of the doubt by excluding from the analysis any of their plants smaller than 50 megawatts in capacity and by using the ISO's database of plant outages, which tends to understate the generators' actual power availability.¹³

Specifically, to determine the quantity of available power that the five generators did not provide to California, the following were subtracted from each plant's generation capacity:

- **Megawatts out-of-service** - this includes all megawatts that were not available as a result of planned or unplanned plant outages.
- **Obligations to provide reserve power** - this includes all capacity that the Five Generators committed to hold in reserve for the ISO in order to follow minute-by-minute load changes or to respond to sudden transmission or generation failures.
- **Actual generation** - this includes all megawatts that the Five Generators actually generated.

Treatment of Generator Reported Plant Outages

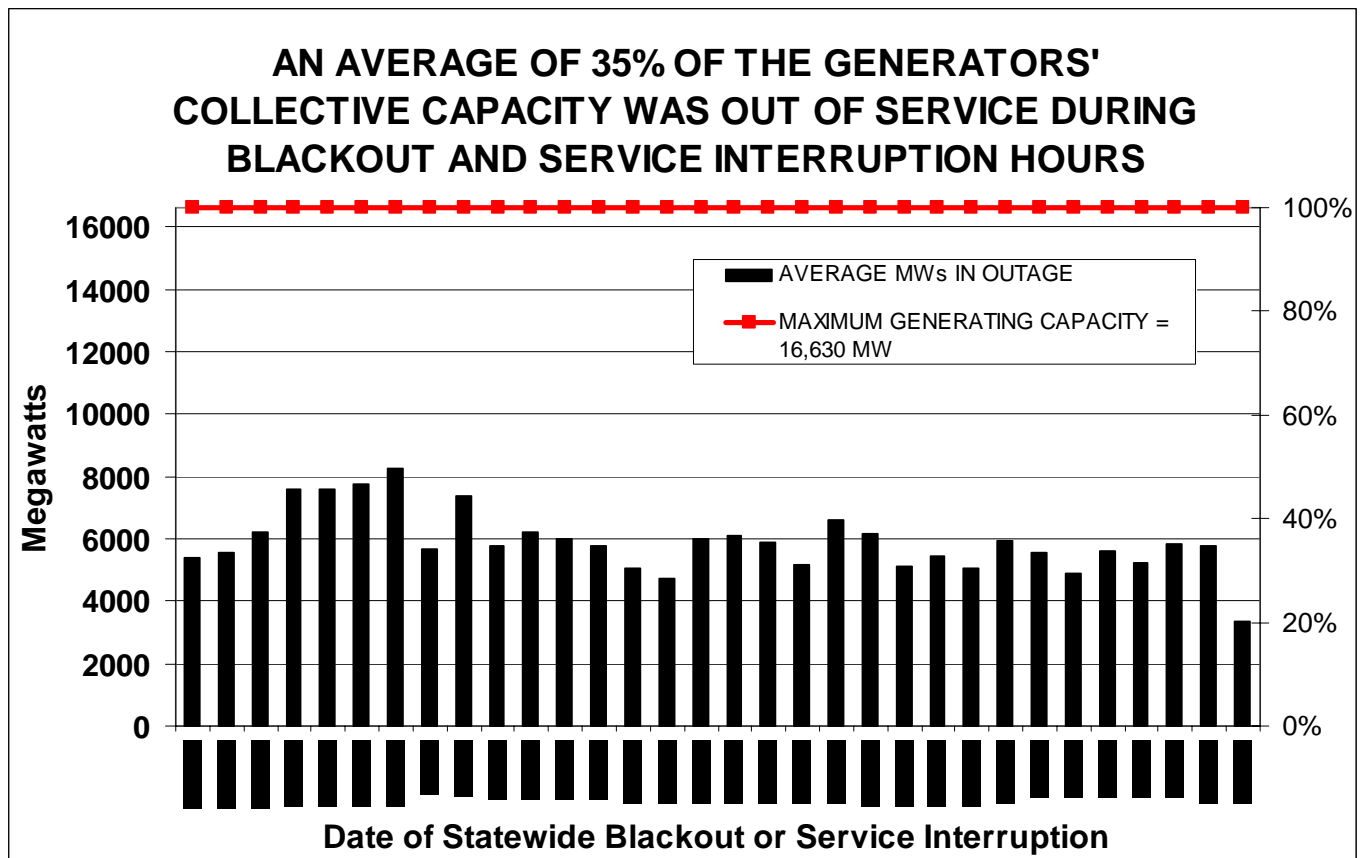
The analysis in this report assumes that all claimed outages of generating capacity were legitimate and necessary, even though (1) rates of plant outages during the crisis, and

¹³ The ISO's database assumes a plant to be out-of-service for an entire hour even if the plant is only out-of-service for a few minutes during that hour. For this reason, the ISO's database shows, over time, even more megawatts to be unavailable than the five generators' own reports would show. By using the ISO's database, which overstates plant outages, the analysis in this report lowers the estimates of available power not generated.

specifically during blackout and service interruption hours, were higher than historical averages, and (2) there is evidence (see Chapter 4 below) that the five generators failed to take all necessary steps to keep plants in service.

Figure 2 presents the number of megawatts reported out of service by the large power plants owned and operated by the five generators on each of the 32 statewide blackout and service interruption days that are the focus of this report.

Figure 2



The maximum generating capacity of the five generators' large power plants totals 16,630 megawatts. This total excludes an additional 399 megawatts of smaller peaking units owned by the five generators.¹⁴ On December 7, 2000, the five generators reported

¹⁴ The units in question are all smaller than 50 megawatts in capacity and include 11 units (capable of generating 336 megawatts) owned by Dynegy, one unit (capable of generating 15 megawatts) owned by Duke, and one unit (capable of generating 48 megawatts) owned by Reliant. If these smaller units had been included in the staff's analysis, the calculations could have shown even more available power not generated

that 8,275 megawatts, nearly 50% of their total capacity, were out of service. Indeed, on all but two of the 32 statewide blackout and service interruption days, the five generators reported that 5,000 megawatts, more than 30% of their total capacity, were out of service.

The data presented in Figure 2 was obtained from a database maintained by the ISO. This ISO database accounts for hour-by-hour changes in megawatts out-of-service, whether for planned maintenance (scheduled outages), to fix a problem (unscheduled, forced outages), or because of air quality restrictions. The ISO used self-reporting from the generators to construct this database, but it did not verify the generators' claimed reason for the outage. The ISO data presented in Figure 2 thus accepts the generators' stated bases for the outages, whether or not those stated bases were actually valid.

Treatment of Capacity Held in Reserve

To explain this report's analysis in technical terms, reserve obligations equal the megawatts bid by generators and accepted by the ISO in the hour-ahead market (that is, hour-ahead capacity schedules) for all ancillary services (Spin, Non-Spin, Replacement and Regulation Up) that require generators to hold back power (thus, Regulation Down is omitted). To avoid double counting, reserve obligations were reduced in the amount that the ISO in fact ordered those plants to generate power.¹⁵

Treatment of Generator Bidding Behavior

In much the same fashion, the total megawatts not bid into the marketplace are calculated by determining the total megawatts of capacity, minus: (a) any plants out of service (as described above, giving the generator the benefit of the doubt); (b) hour-ahead energy schedules (through the PX, or, later, DWR); (c) all valid bids into the last-minute supplemental energy market; and (d) all agreements to supply power outside of normal ISO/PX markets (sometimes known as "out-of-market" or "OOM" power). Any reserve obligations (also described above) were also subtracted from total capacity. No

than the results shown in Chapter 3 below. Thus, excluding these units gives the five generators an additional benefit of the doubt.

¹⁵ The ISO activates generation held in reserve through an "automatic dispatch system," or "ADS." For the purposes of this analysis, such activated reserves are included as part of the actual generation data received from the ISO. We are unable to reduce Regulation Up and Regulation Down reserve obligations to account for the amount that the ISO actually ordered the plants to provide those services, because these services are dispatched through Automatic Generation Control on a nearly instantaneous basis, and there is no useable record of such dispatches. However, in general, dispatch by the ISO of Regulation Up and Regulation Down should roughly balance out, in which case, it is a wash for the purposes of this analysis.

adjustment was made for actual ISO dispatches, because this part of the analysis examines bids, not actual generation.

In these calculations, bids are not considered valid if the ISO ordered a generator to produce power pursuant to a bid by that generator, and the generator failed to respond to or rejected the dispatch for “economics.” If the generator rejected the ISO order because of other problems, including mechanical failure, the bid is counted. In calculations of megawatts not bid, by using the ISO database of plants out-of-service, the five generators receive the same benefits of the doubt noted above in connection with the analysis of megawatts not generated. The generators receive an additional benefit of the doubt in the analysis of megawatts not bid, because they are given full credit for all OOM sales. While these OOM sales did help avoid outages, to the extent that they were last minute sales, they impeded ISO operations, and may have been part of a strategy by certain generators to game the market and artificially increase prices. However, the analysis set forth in this report focuses on the availability of power to avoid blackouts and service interruptions; it does not address the gaming and potential price manipulation that appear to have occurred during the energy crisis.¹⁶

Treatment of Path 15 Congestion

This study estimates the capacity available to ship power across Path 15, a crucial link in the transmission lines connecting Northern and Southern California,¹⁷ using data provided by the ISO, which is assumed to be valid data. That data shows, among other things, actual flows on Path 15, as well as the maximum flow allowable under rules promulgated by the ISO and the Western Electricity Coordinating Council (WECC).¹⁸ In general, the ISO is obligated to keep path flows under limits, and to correct overloads within a few minutes, to avoid serious problems that could spread throughout the Western Grid.¹⁹ Thus, ISO operators generally try to leave a safety margin to allow for changes in

¹⁶ See Chapter 5 below.

¹⁷ Path 15 falls within the service territory of Pacific Gas & Electric Company, connecting its southernmost transmission substation, Midway, with the Gates substation in Central California. From Gates, the power lines comprising Path 15 run south to Southern California Edison’s northernmost substation, Vincent, and then to Los Angeles.

¹⁸ Formerly known as the Western Systems Coordinating Council, or WSCC, before its merger with other Regional Transmission Associations within the last 12 months.

¹⁹ The WECC’s standards require that the electric system be able to withstand the sudden failure of two large generation or transmission facilities (known as “contingencies”). In general, when transmission paths are heavily used, a greater likelihood exists that such contingencies could cause serious problems that could

system conditions.²⁰ But the ISO does not document these minute-by-minute decisions about how large this safety margin should be.²¹ Therefore, the analysis assumes a prudent safety margin of 200 megawatts. For each hour, this study calculates the additional available room on Path 15 as the path limit²² minus the actual peak flow minus 200 megawatts. To test the sensitivity of results to this assumption, the analysis alternatively tests a more conservative safety margin of 600 megawatts and a less conservative safety margin of 50 megawatts.²³

To the extent Path 15 had unused capacity, power from the South could be used to relieve blackouts or service interruptions in the North (and vice versa). To determine how much power could have been moved from the South to the North, this analysis assumes first that power that was available but not generated in each half of the state would have been used first in that part of the state to relieve blackouts. Then, to the extent Path 15 has additional capacity, the analysis assumes that remaining unused generation in the South is moved to the North to relieve any blackouts there. Then, any remaining unused generation in Southern California is used to relieve non-firm service interruptions in that part of the state. Finally, the amount of power available to relieve non-firm service interruptions in Northern California is calculated as follows: first, by applying any remaining unused generation in Northern California; second, by applying any remaining unused generation in Southern California to the extent that Path 15 still has available capacity to accommodate that power transfer. Similar calculations were performed to

spread across the West, causing widespread, uncontrolled blackouts and even serious damage to generation and transmission facilities. Therefore, limits are set through modeling studies that simulate contingencies at various flow levels; limits are set as high as possible while keeping the system safe from those contingencies.

²⁰ Such changes include unintended (“loop”) flows on the transmission system, or major “ramps” when generation goes on or off line at the end of the hour, in or outside the control area.

²¹ The ISO stated that safe limits might be inferred by examining all ISO operations data minute-by-minute.

²² In some groups of hours, the ISO did not provide a figure for the allowable flow, due to “calculation errors.” For these hours, the allowable flow is set at the average allowable flow for ten hours before and after the failure. In a few scattered hours, the ISO did not provide that figure because of “input-output timeout” error. In those cases, the allowable flow is set at the minimum of the flows in the two adjoining hours. As discussed, the results vary little with changes in these assumptions.

²³ As discussed below, the results vary little with changes in these assumptions. Before mid-February, Path 15 operated close to its limits; afterwards, there was substantial available capacity on the line.

determine whether power could be moved from the North to relieve blackouts and service interruptions in the South.²⁴

A final element of conservatism arises from the fact that this report does not analyze, and provides no data on, the potential availability of significant unused capacity on the transmission inter-tie between California and the Pacific Northwest. Using this alternative route to Path 15, available Southern California power could have been wheeled across the direct current transmission line connecting the service area of the Los Angeles Department of Water and Power to the Pacific Northwest and then back to Northern California via alternating current transmission lines connecting California to the Pacific Northwest. Had this alternative route been available, it is likely that additional hours of blackouts and service interruptions, especially in Northern California, could have been avoided.

Although the investigation to date has yielded important conclusions pointing to the role of the five generators in contributing to the energy crisis and the associated serious disruptions to the California economy, considerable additional work remains. Accordingly, this study does not attempt to answer fully the question of why, at each plant and for each hour, the generators did not generate all available power during each service interruption hour.

²⁴ However, the analysis shows that little power was available in Northern California to send to Southern California. The results of this analysis are provided in **Appendix C**.

Chapter 3

Blackouts and Service Interruptions Could Have Been Avoided

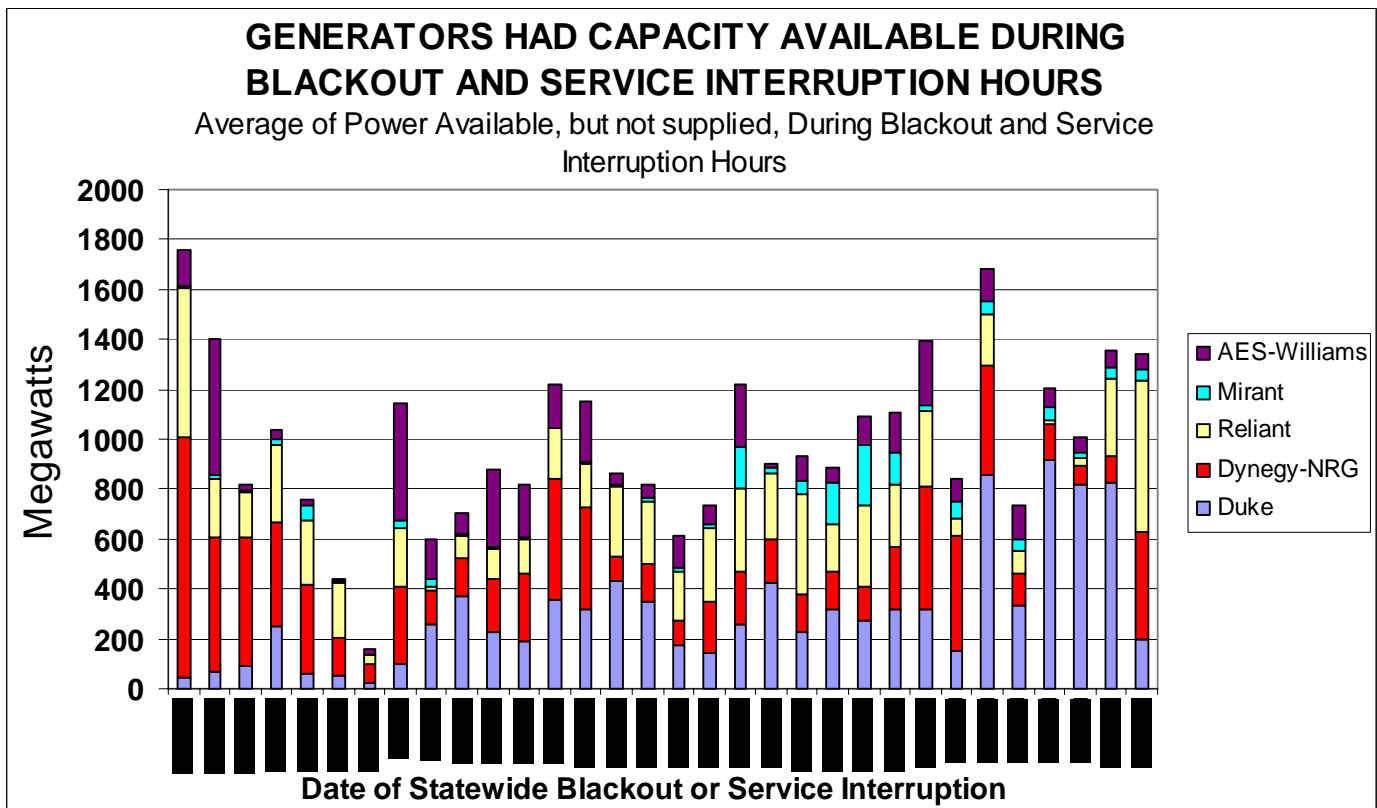
This report compares unused, but available, potential electricity generation that the five generators could have produced versus the shortages of megawatts that led to blackouts and service interruptions during the crisis. The report concludes that most of the blackouts and service interruptions could have been avoided.

The Generators Did Not Produce All Available Power on Blackout and Service Interruption Days

On most of the 32 days of statewide blackouts or service interruptions between November 2000 and May 2001, the five generators had sufficient available unused capacity to prevent or substantially alleviate these blackouts and service interruptions.

Figure 3 shows power not generated during the 32 days when both Northern and Southern California experienced blackouts or service interruptions. Figure 3

Figure 3



On all but 2 of the 32 statewide blackout and service interruption days studied, the five generators did not produce well over 500 megawatts of power that they could have generated.

demonstrates that while the five generators had unused capacity available on the 32 statewide blackout and service interruption days, they did not generate this power. For example, the first bar on Figure 3 demonstrates that on November 13, 2000, service interruptions occurred despite the fact that approximately 1,750 megawatts²⁵ of power were available, but not generated, during the service interruption hours occurring on that day.^{26, 27}

Figure 3 also demonstrates that on all but two of the 32 statewide blackout and service interruption days shown, the five generators collectively did not produce well over 500 megawatts (and on many days, far more) that they could have generated. Figure 3 also shows that there was only one day, December 7, 2000, on which the entire state experienced a service interruption for which it appears that very little extra power (slightly over 100 megawatts) was available for generation.

The service interruption that occurred on December 7, 2000 is special case. The fact that December 7 is also the date on which it appears that the most available generation was not bid into ISO real-time markets seems anomalous. It appears that several generators

²⁵ 1 megawatt-hour = 1 million watts over the time span of 1 hour. 1 kilowatt-hour = 1000 watts over a time span of 1 hour. As a general rule, 1 megawatt-hour could power approximately 750 homes for 1 hour; 1 kilowatt-hour could run a hair dryer for 1 hour.

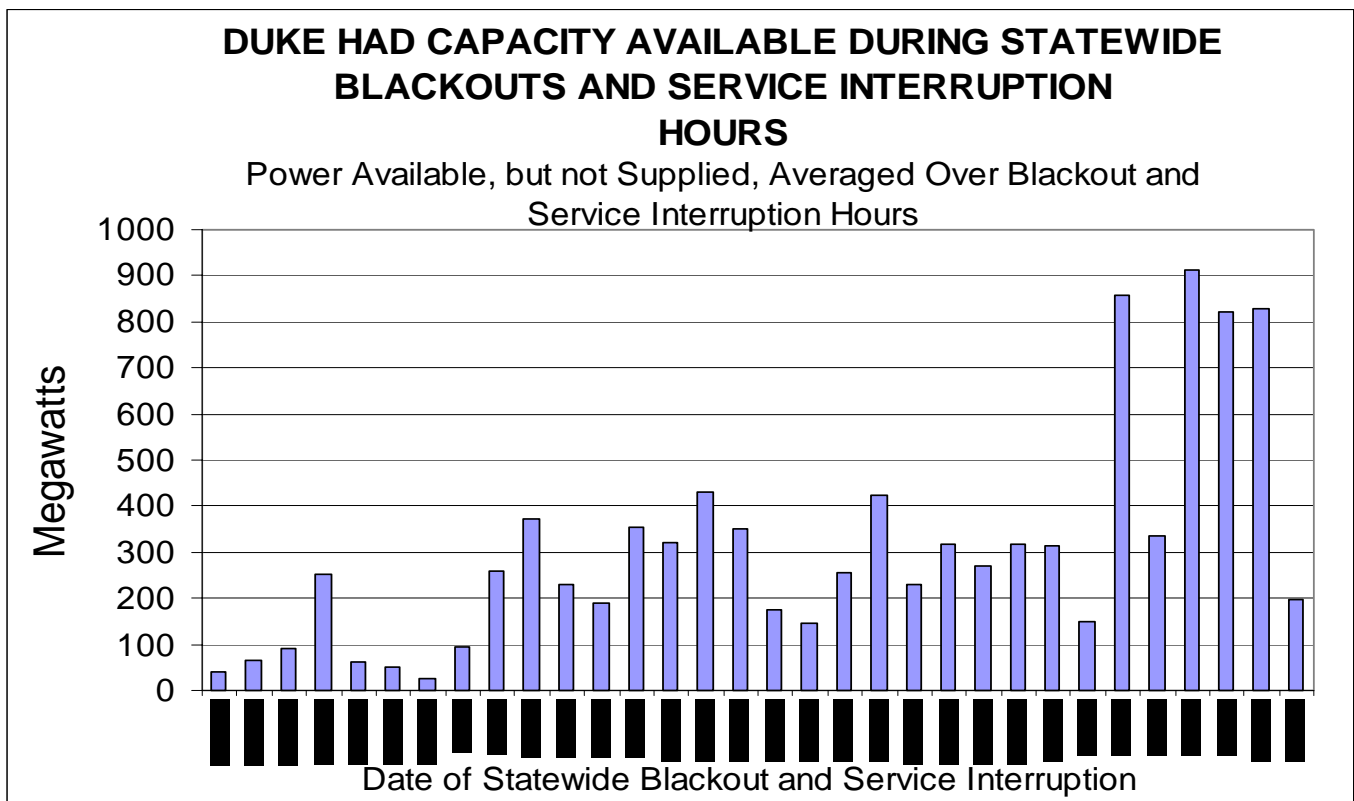
²⁶ Although the data summarized on Figure 3 shows the number of megawatts available but not generated on an average hourly basis for each of the 32 days depicted, this average data is based on the actual number of megawatts available but not generated for each hour in which there was a blackout or service interruption on that day. The hour-by-hour data that underlies the results set forth in Figure 3 is provided in **Appendix A** to this report. Appendix A provides detailed, hour-by-hour data, for each blackout and service interruption hour on the 32 days covered by Figure 3, indicating: (1) the number of megawatts available, but not generated, by each of the 5 scheduling coordinators, and (2) the number of megawatts not bid by each of the 5 scheduling coordinators, and comparing this data to the number of megawatts of power actually curtailed, both for firm and non-firm load.

²⁷ While this report concentrates on hours with **statewide** blackouts and service interruptions, results are very similar for hours with **non-statewide** blackouts and interruptions, that is, those that affected either Northern or Southern California, but not both. During **statewide** blackout and service interruption hours, generators averaged 81 and 861 megawatts of power available but not generated in Northern and Southern California respectively. During **non-statewide** interruption hours, generators averaged 73 and 876 of available power not generated, respectively. Appendix A presents detailed data on both statewide and non-statewide blackouts and interruptions.

actually produced power on that day even though they had not bid it into the market, and the ISO had accordingly not instructed them to generate this power. Also, Figure 2 shows that December 7, 2000 was the date on which there was the greatest number of plant outages during the period under study. December 7, 2000 was also the date upon which the ISO relied to request that the price caps then in effect be lifted. In any case, December 7 was an unusual day.²⁸

The data presented in Figure 3 is broken down into greater detail, on a generator-by-generator basis, in **Figures 3.1 through 3.5**. Figures 3.1 through 3.5 show that each of the five generators had available unused capacity that was not generated during the blackout and service interruption hours on each of the days depicted in Figure 3. The discussion following Figures 3.1 through 3.5 shows that each of the five generators did not generate a significant amount of available power on certain statewide blackout and service interruption days.

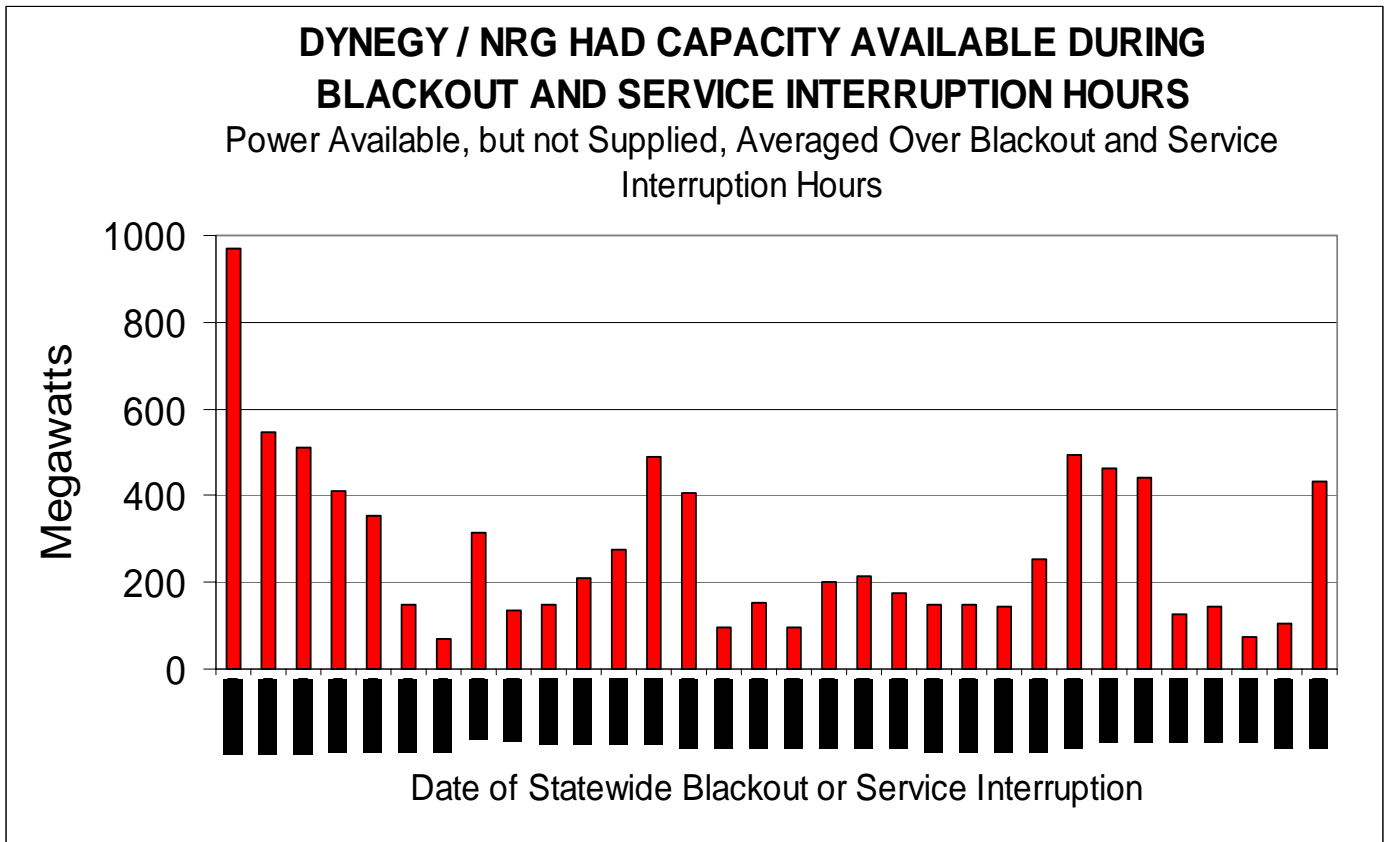
Figure 3.1 - Duke



²⁸ Although there were several other dates among the 32 presented in Figures 3 and 4 on which more power was not bid than was not generated, December 7, 2000 is the extreme example, and does not contradict the basic premise that the failure of the generators to bid into the market was a major reason why they did not generate.

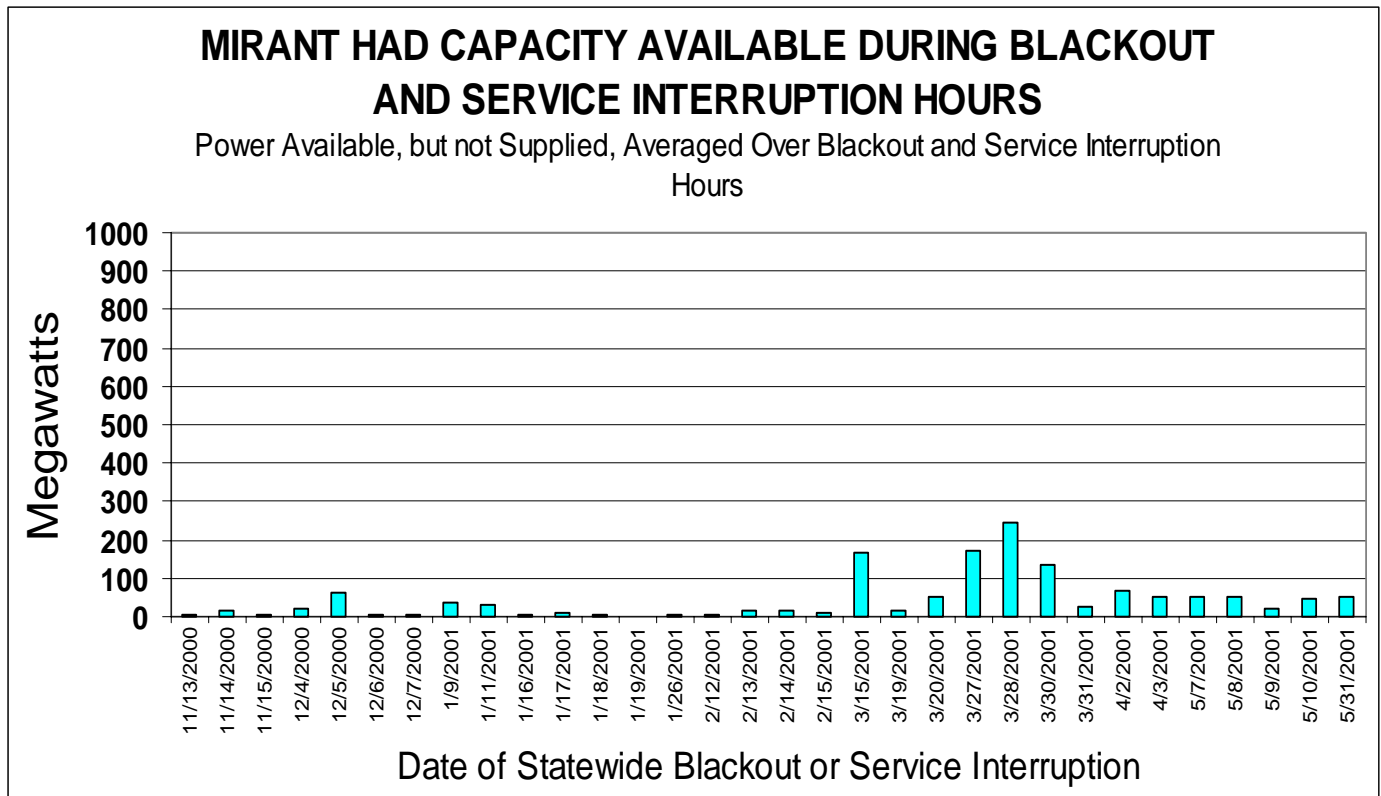
- Figure 3.1 shows that Duke had, on average, over 800 megawatts available and unused during the blackouts and service interruption on May 8, 9 and 10, 2001.
- As shown in Appendix A, there were blackouts of 400 megawatts between 3 p.m. and 5 p.m. on May 8. However, Duke did not generate, respectively, 916 and 1,055 megawatts of available capacity during those two hours. **Thus, Duke alone had more available and unused power than the total amount of power that was needed to avoid the blackout on that day.**
- As is also shown in Appendix A, service interruptions to non-firm customers on May 9 and 10 were caused, respectively, by shortages of 863 and 913 megawatts. On May 9, Duke had between 759 and 893 megawatts of available and unused power, and on May 10, Duke had between 574 and 974 megawatts of available and unused power. **Thus, Duke alone had available and unused power to meet most of the needs of the non-firm customers whose service was interrupted on those days.**
- Figure 3.1 also shows that Duke had, on average, between 200 and 400 megawatts of available and unused power during blackout and service interruption hours on an additional 17 of the 32 statewide blackout and service interruption days. **Had Duke generated this power, the blackouts and service interruptions on those 16 days would have been significantly alleviated.**

Figure 3.2 - Dynegy



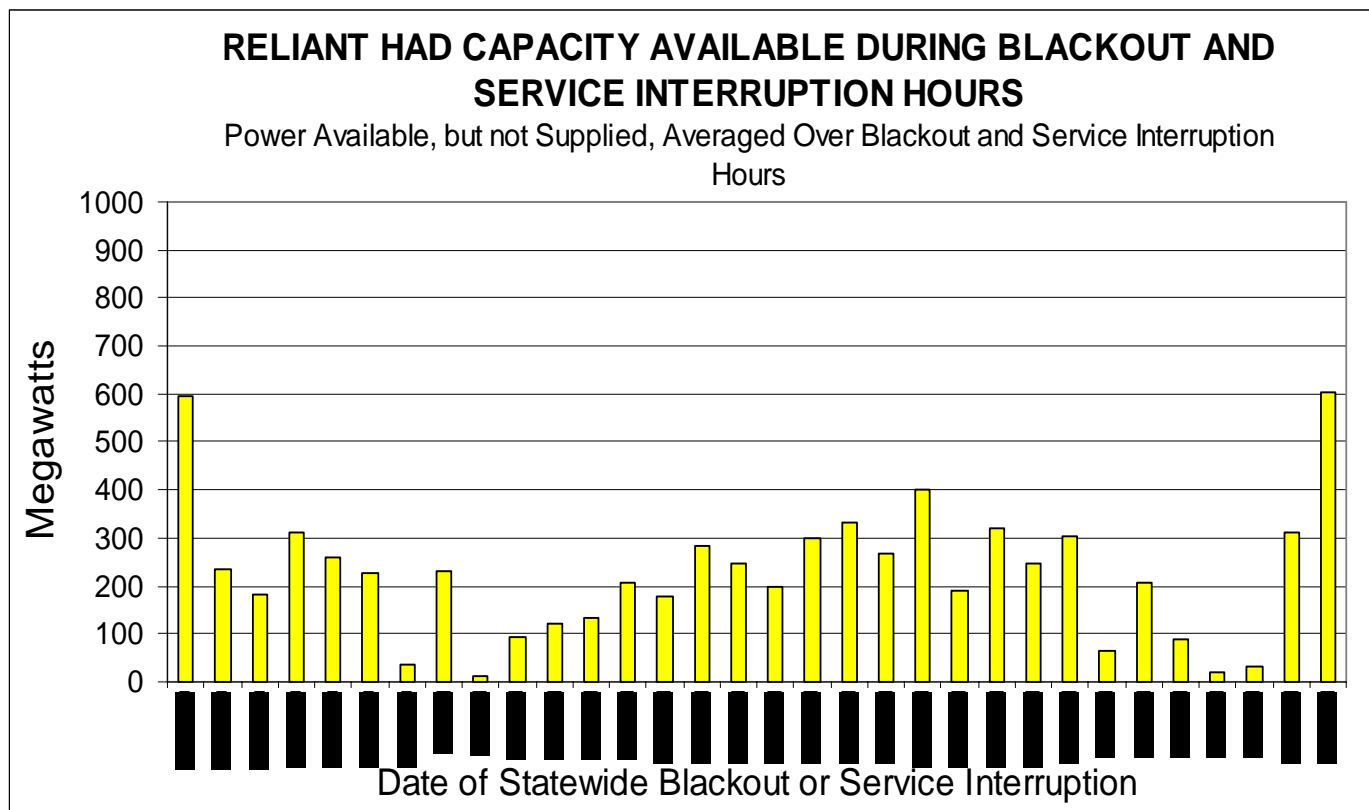
- Figure 3.2 shows that Dynegy had nearly 1,000 megawatts of available and unused power during service interruption hours on November 13, 2000. As shown in Appendix A, a shortage of 1,857 megawatts caused service interruptions on that day. **Thus, Dynegy alone had available and unused power to meet fully one-half of the amount of service interruptions that took place on that day.**
- Figure 3.2 also shows that Dynegy had over 200 megawatts of available and unused power during service interruption hours on an additional 13 of the 32 statewide blackout and service interruption days. **Had Dynegy generated this power, the service interruptions occurring on those 11 days would have been significantly alleviated.**

Figure 3.3 - Mirant



- Figure 3.3 shows that Mirant had, on average, available but unused capacity of over 200 megawatts during the service interruption hours on March 28, 2001. On that day, a shortage of 135 megawatts caused service interruptions. **Thus, by itself, Mirant had enough available but unused power to meet the needs of non-firm customers whose service was interrupted on that day.**

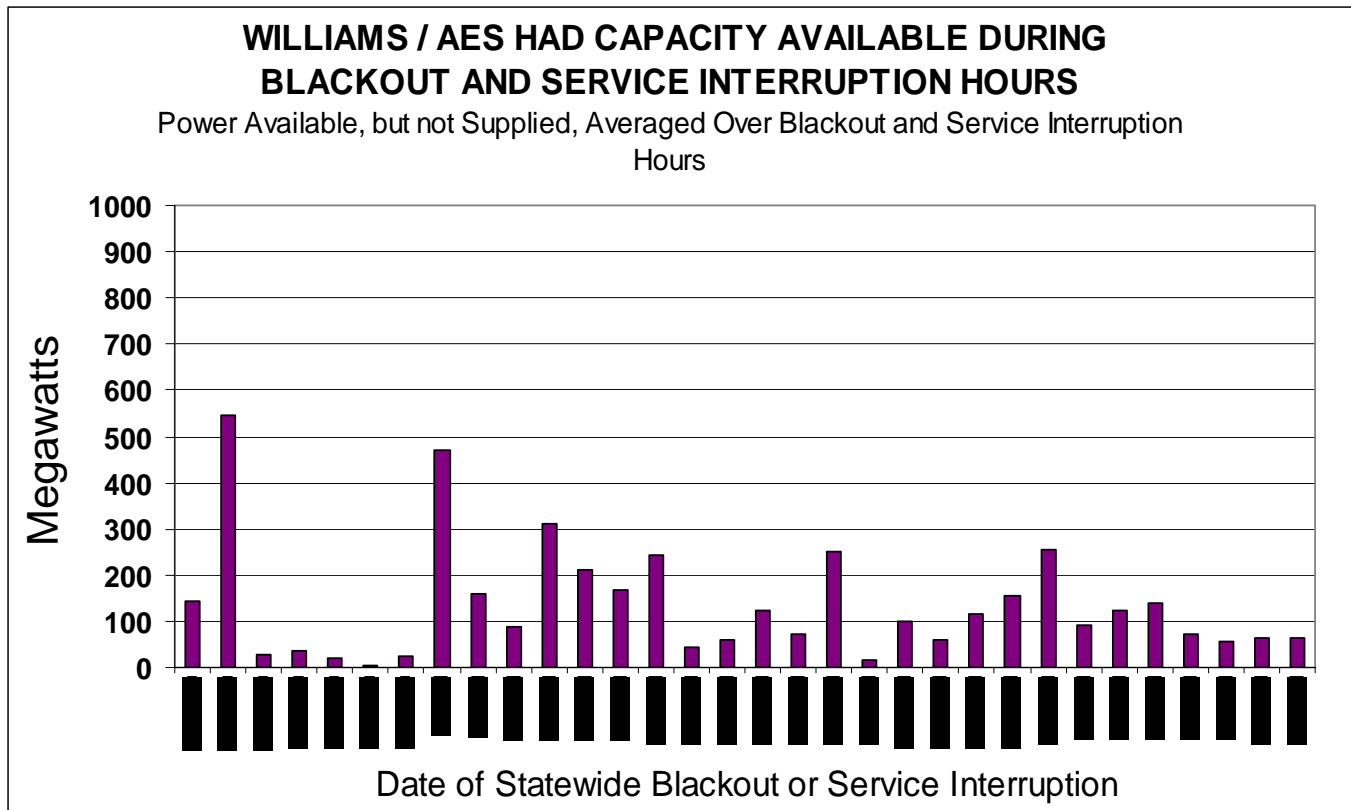
Figure 3.4 – Reliant



- Figure 3.4 shows that Reliant had, on average, nearly 600 megawatts of capacity during the service interruption hours on November 13, 2000 and May 31, 2001. As noted above, a shortage of 1,857 megawatts caused service interruptions on November 13, 2000. **Thus, Reliant’s available and unused power on that day, along with Dynegy’s nearly 1,000 megawatts of available but unused power, were enough to meet the most of the needs of customers subject to the service interruptions occurring on November 13, 2000.**
- On May 31, 2001, as shown in Appendix A, service interruptions resulted from a shortage of 783 megawatts. **Thus, Reliant alone had available and unused power to meet the needs of three-quarters of the non-firm customers who experienced service interruptions that day.**
- Figure 3.4 also shows that Reliant had, on average, between 200 and 400 megawatts of available power during blackout and service interruption hours on an additional 16 of the 32 statewide blackout and service interruption days. **Had**

Reliant generated this power, the blackouts and service interruptions occurring on those 15 days would have been significantly alleviated.

Figure 3.5 – Williams/AES



- Figure 3.5 shows that Williams/AES had, on average, over 500 megawatts of available and unused power during the service interruptions on November 14, 2000 and over 400 megawatts of available and unused power during the service interruptions on January 9, 2001. On November 14, 2000, a 1,412-megawatt shortage caused service interruptions, and on January 9, 2001, a 1,131-megawatt shortage caused service interruptions. **Williams/AES had sufficient available and unused power to meet the needs of over one-third of the non-firm customers who experienced service interruptions on those two days.**
- Figure 3.5 also shows that Williams/AES had, on average, over 200 megawatts of available and unused power during service interruptions on an additional five of the 32 statewide service interruption days. **Had Williams/AES generated this**

power, the service interruptions occurring on those five days would have been significantly alleviated.

The data thus shows that the five generators did not produce all power they had available on the 32 days that are the focus of this Report.

Generators Also Did Not Bid All Available Power Into the Markets on Blackout and Service Interruption Days

The discussion above demonstrates that the five generators did not generate all their available power on 32 statewide blackout and service interruption days during the energy crisis. They did not generate all available power on those days in significant part because they did not bid all available power into the ISO real-time market on those days.

Prior to the deregulation of California's electric-power market in 1998, bidding was not an issue. Utilities received power from power plants they owned, from other utilities, or under long-term contracts with independent generators. Typically, these plants and the power bought under contract were dispatched to meet the demand for electricity on an economic basis. This means that in general, the utilities preferentially generated power from the most efficient plants first, and only generated power from their least efficient plants during peak hours when demand was highest.

In California's new restructured system, a close relationship exists between a generator's failure to "bid" its generation into the markets and that generator's failure to "generate."

AB 1890, the electric utility restructuring law, replaced this regulated system with a market system. The utilities were encouraged to sell most of their conventional plants (mostly natural gas-fired units) to other companies. The companies that bought these plants, the five generators, would henceforth operate these plants as wholesale electricity generators and would bid the power that these plants could produce into one of the new markets that AB 1890 created at the PX and the ISO.

Proponents of this new market system expected that wholesale generators would compete against each other, and thereby provide the power to the utilities at the lowest price possible. In particular, generators were expected to bid available power into the new

markets to maximize sales and profits. Unfortunately, the ISO markets were not designed to avoid the possibility that by withholding some of their power, generators could drive prices up and make abnormally high profits on the power they did generate. AB 1890 imposed no obligation on the generators to bid all of their available generation into the markets. From December 14, 2000 to February 9, 2001, DOE required generators and energy traders to provide all available power in response to nightly ISO requests, but as is shown below, this requirement did not result in the five generators' bidding all their available power into the ISO's markets.²⁹ This fatal flaw in the system was rectified, at least temporarily and in part, only after the crisis, when the FERC imposed comprehensive market controls in June 2001, including a price cap, trading barriers to prevent some types of market manipulation and a "must-offer" obligation that required generators to bid all available power into the market.

During the period of time covered by this report, the generators were not required to bid their available power into the new energy markets. If a generator neither bid power into markets nor supplied that power "out-of-market" to the ISO, the ISO could not dispatch that power to meet electricity demand within its control area. Thus, in California's new restructured system, a generator's failure to bid its generation into the markets can directly affect that generator's failure to generate. This relationship is not one-to-one, in part because generators have sometimes deviated from ISO dispatch instructions.

Figures 3 through 3.5 above show the results of ISO and generator operations during the statewide blackouts and service interruptions. By contrast, Figures 4 through 4.5, which follow, show the bidding data on which these ISO and generator operations were based.

The results presented in **Figure 4** are based on an examination of the extent to which the five generators bid in all available power on the 32 statewide blackout and service interruption days that are the focus of this report. This examination focuses on the real-time market, which closes 45 minutes before each hour. By this time, the generators knew their commitments in all other markets, and could have bid in all their remaining power into California's market.

²⁹ These DOE orders were issued on December 14, 20, and 27, 2000, and January 5, 11, 17, and 23, 2001.

Figure 4

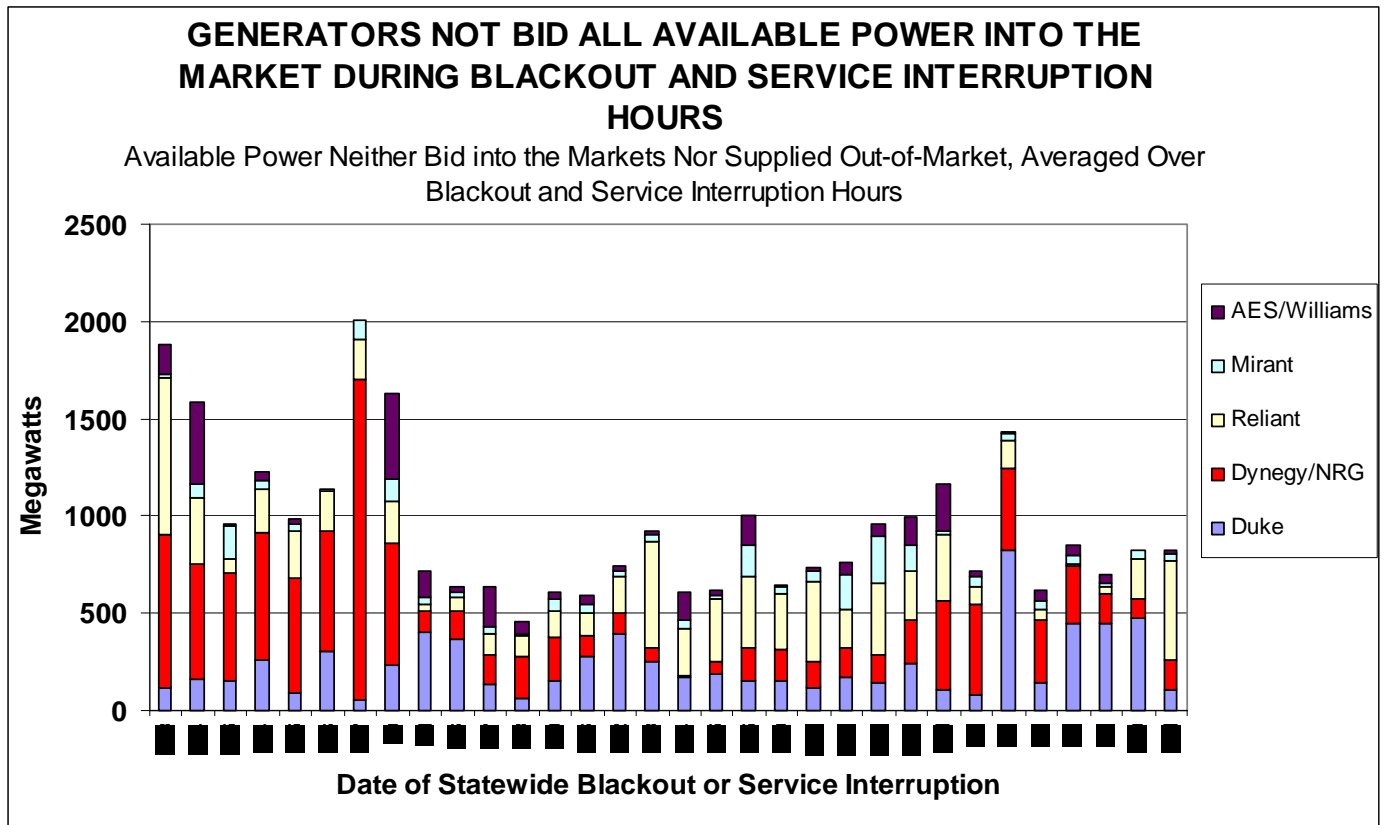


Figure 4 shows that the five generators reported significant numbers of megawatts to be available but not bid into the market during the 32 statewide blackout and service interruption days studied in this report.^{30, 31} For example, the largest number of megawatts available but not bid in occurred on December 7, 2000, when approximately 2,000 available megawatts were not bid into the market. Of this 2,000 megawatts, approximately 100 available megawatts were not bid in by Duke; over 1,500 available

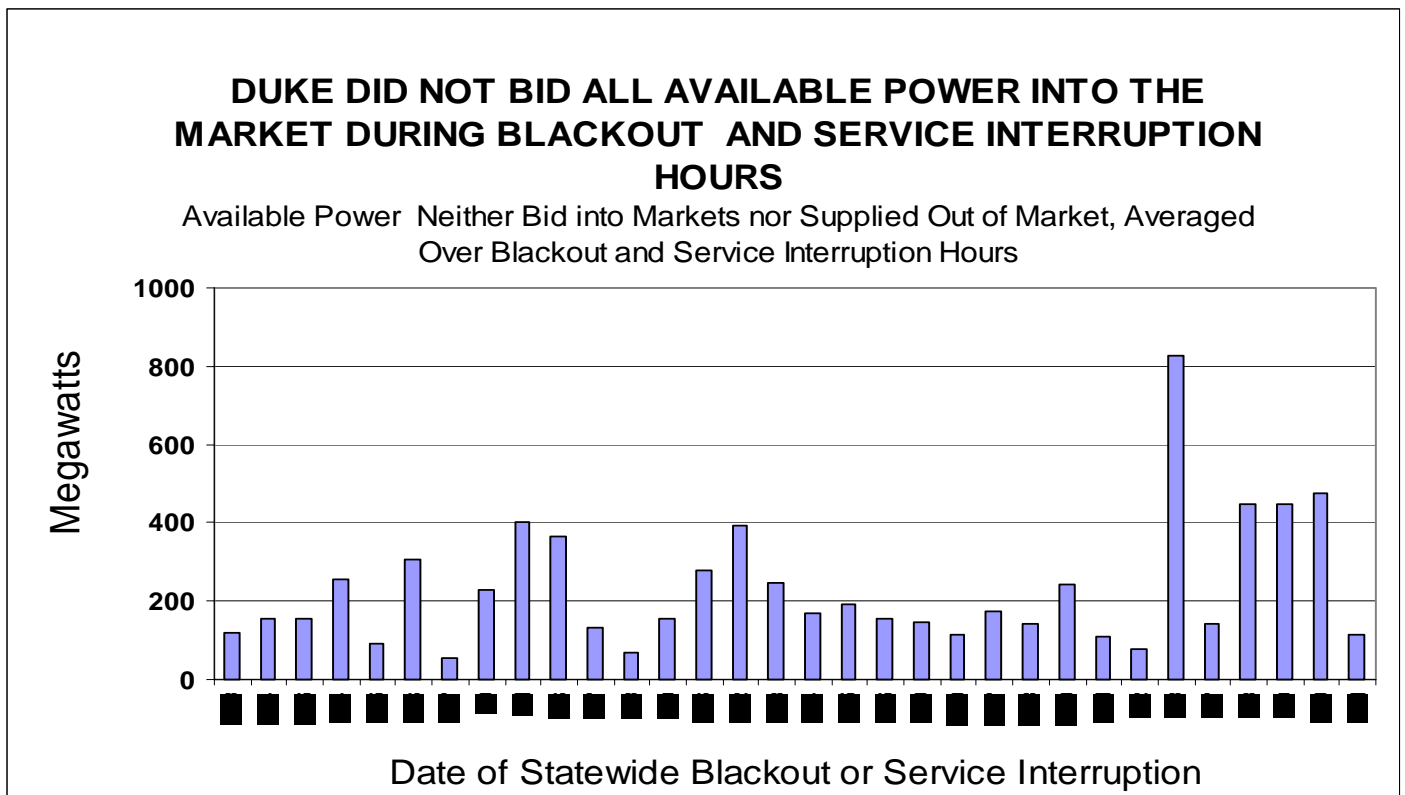
³⁰ As noted in Chapter 2, the analysis presented in Figure 4 gives the generators the benefit of the doubt. First, this analysis includes not only all bids into the ISO markets, but also all power that the generators sold outside of normal ISO markets, even though some of those out-of-market sales were almost certainly high pressure and high-priced last-minute deals. Second, this analysis accounts for plants that were out of service in each hour.

³¹ As was discussed in footnote 27, this report concentrates on hours with **statewide** blackouts and service interruptions. Results on power not bid, as displayed in Figure 4, are also very similar for hours with **non-statewide** blackouts and interruptions, that is, those that affected either Northern or Southern California, but not both. During **statewide** blackout and service interruption hours, generators did not bid in an average of 778 megawatts of available power; during **non-statewide** interruption hours, generators did not bid in an average of 1,134 megawatts of available power. Appendix A presents detailed data on non-statewide blackouts and interruptions.

megawatts were not bid in by Dynegy; approximately 200 available megawatts were not bid in by Reliant; and approximately 100 available megawatts were not bid in by Mirant.

As with Figure 3, the data presented in Figure 4 is broken down into greater detail on a generator-by-generator basis in **Figures 4.1 through 4.5** below. Figures 4.1 through 4.5 show more specifically the amounts of available power that each of the five generators refrained from bidding into the market on the 32 statewide blackout and service interruption days examined in this Report. The figures presented in Figures 4.1 through 4.5 above reveal that the five generators collectively failed to bid significant amounts of available power in to the market on all 32 days studied in this Report.

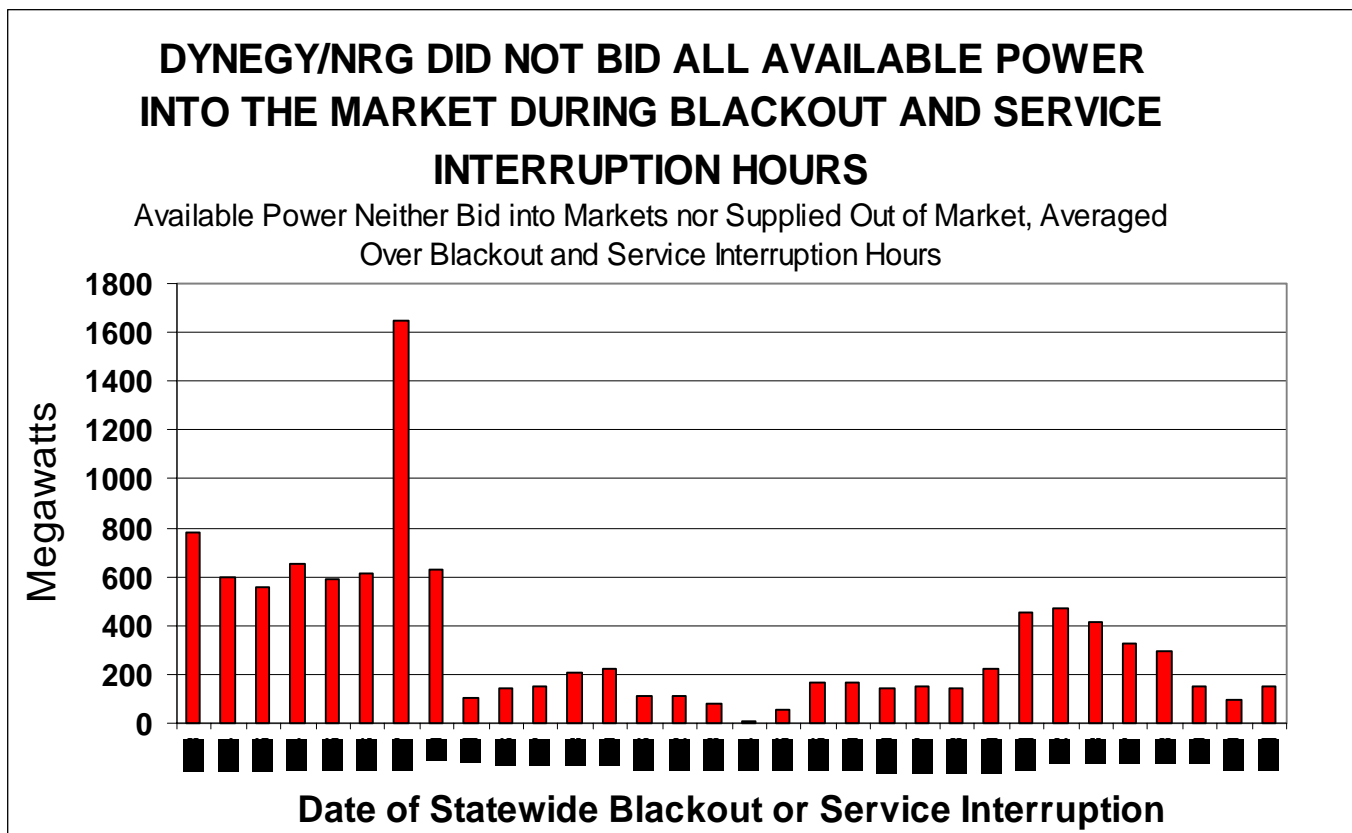
Figure 4.1 - Duke



- Figure 4.1 shows that Duke did not bid over 400 megawatts of available power on May 8, 9 and 10, 2001. More specifically, Appendix A shows that Duke had available, but did not bid, more than 400 megawatts of available power during each of the blackouts and service interruptions that occurred on those three days.

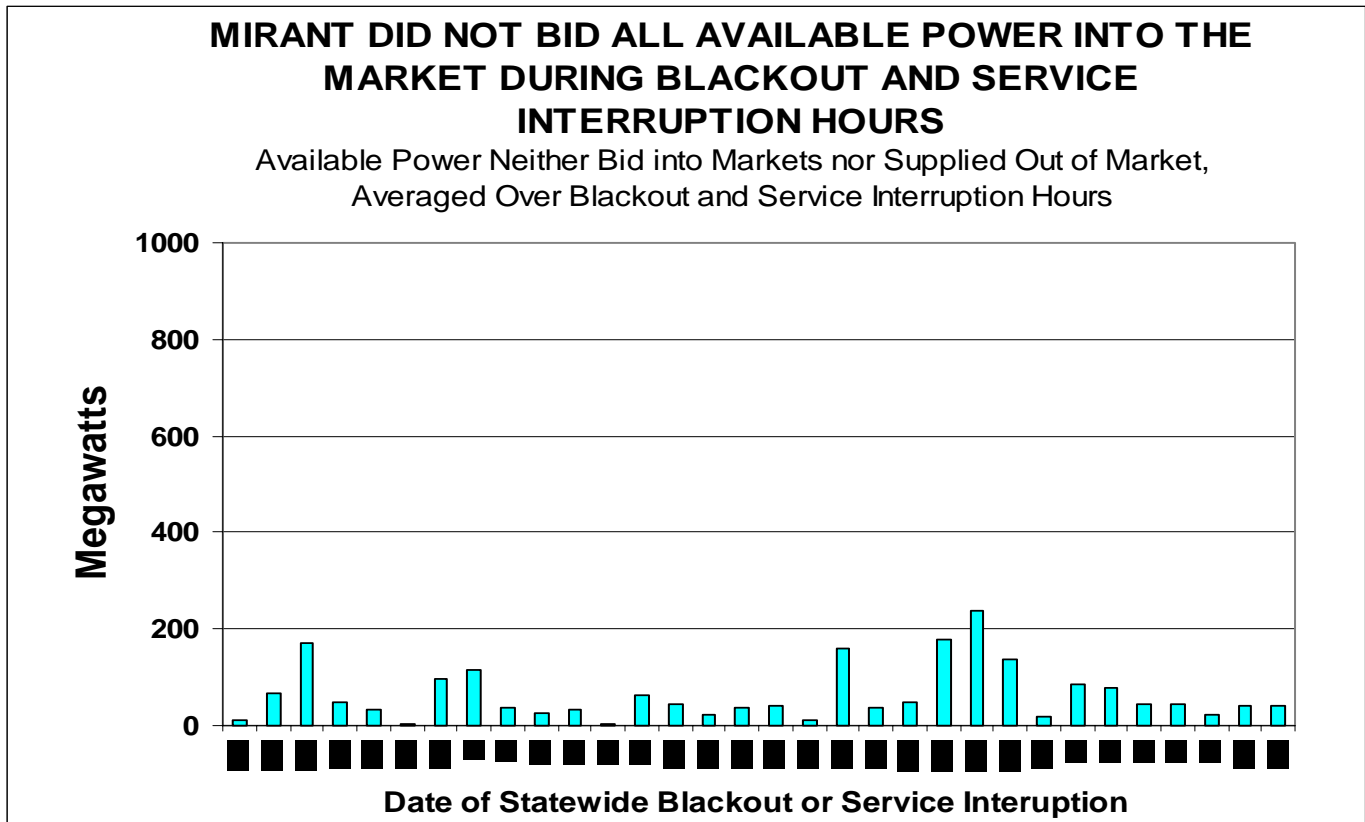
- As noted above, blackouts were caused by shortages of 400 megawatts between 3 p.m. and 5 p.m. on May 8, 2001. **Thus, Duke had more available power to bid than the power shortages that caused the blackouts on that day.**
- Service interruptions to non-firm customers on May 9 and 10 were, respectively, 863 and 913 megawatts. **Thus, by itself, Duke could have, but did not, bid available power into the ISO's real time market in an amount equivalent to one-half of the needs of the non-firm customers whose service was interrupted on those days.**
- Figure 4.1 also shows that Duke had, on average, over 200 megawatts of available power that it did not bid into the ISO's real time market on an additional 10 of the 32 statewide service interruption days. **Thus, Duke did not bid available power into the market in an amount equivalent to a substantial fraction of the service interruptions occurring on those 9 days.**

Figure 4.2 - Dynegy



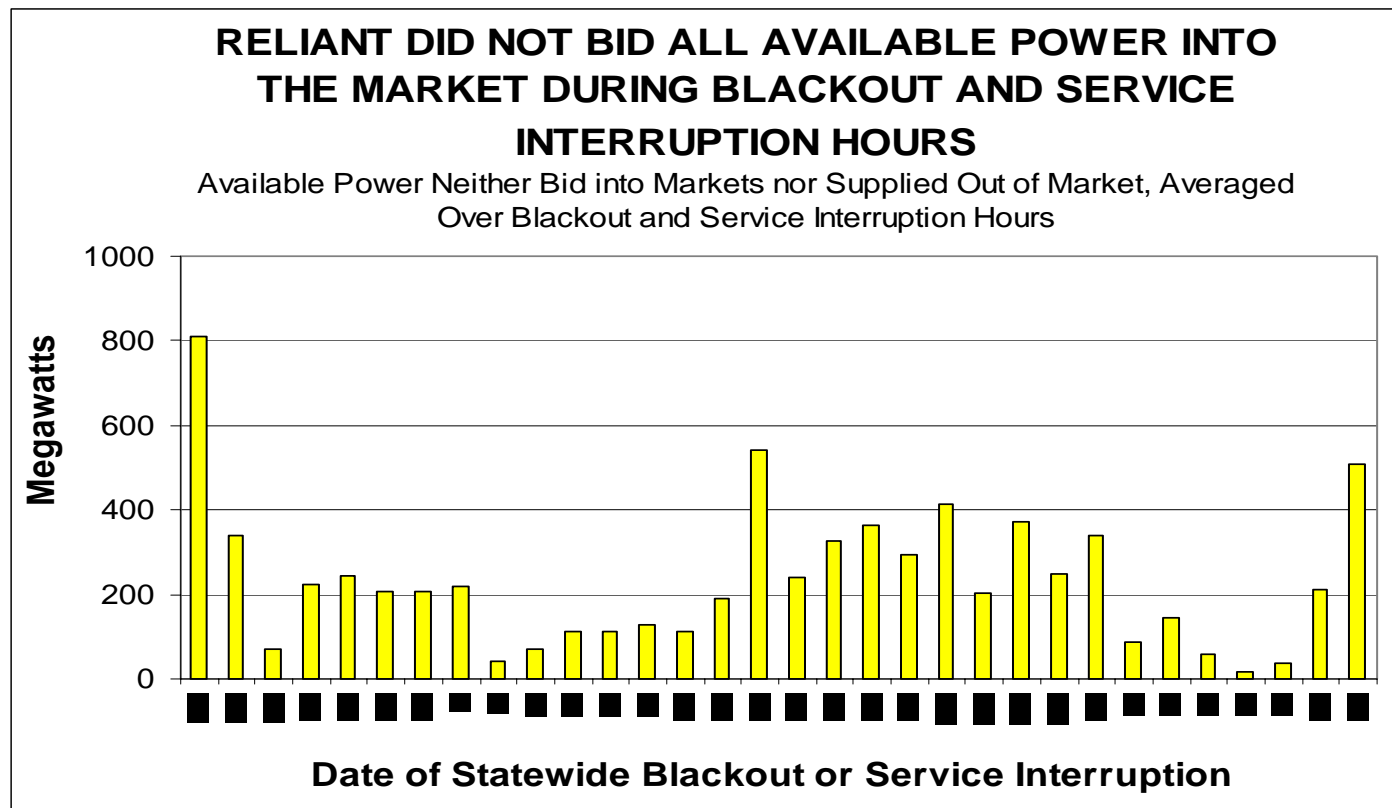
- Figure 4.2 shows that Dynegy had, on average, over 400 megawatts of available power that it did not bid into the ISO's real time market on 11 of the 32 statewide blackout and service interruption days. **Thus, Dynegy did not bid available power into the market in an amount equivalent to a substantial fraction of the service interruptions occurring on those 11 days.**

Figure 4.3 - Mirant



- Figure 4.3 shows that on March 28, 2001, Mirant had, on average, over 200 megawatts of available power that it did not bid into the ISO's real time market during service interruption hours. On that day, a shortage of 135 megawatts caused service interruptions. **Thus, by itself, Mirant did not bid available power into the market in an amount equivalent to the total amount of service interruptions occurring on that day.**

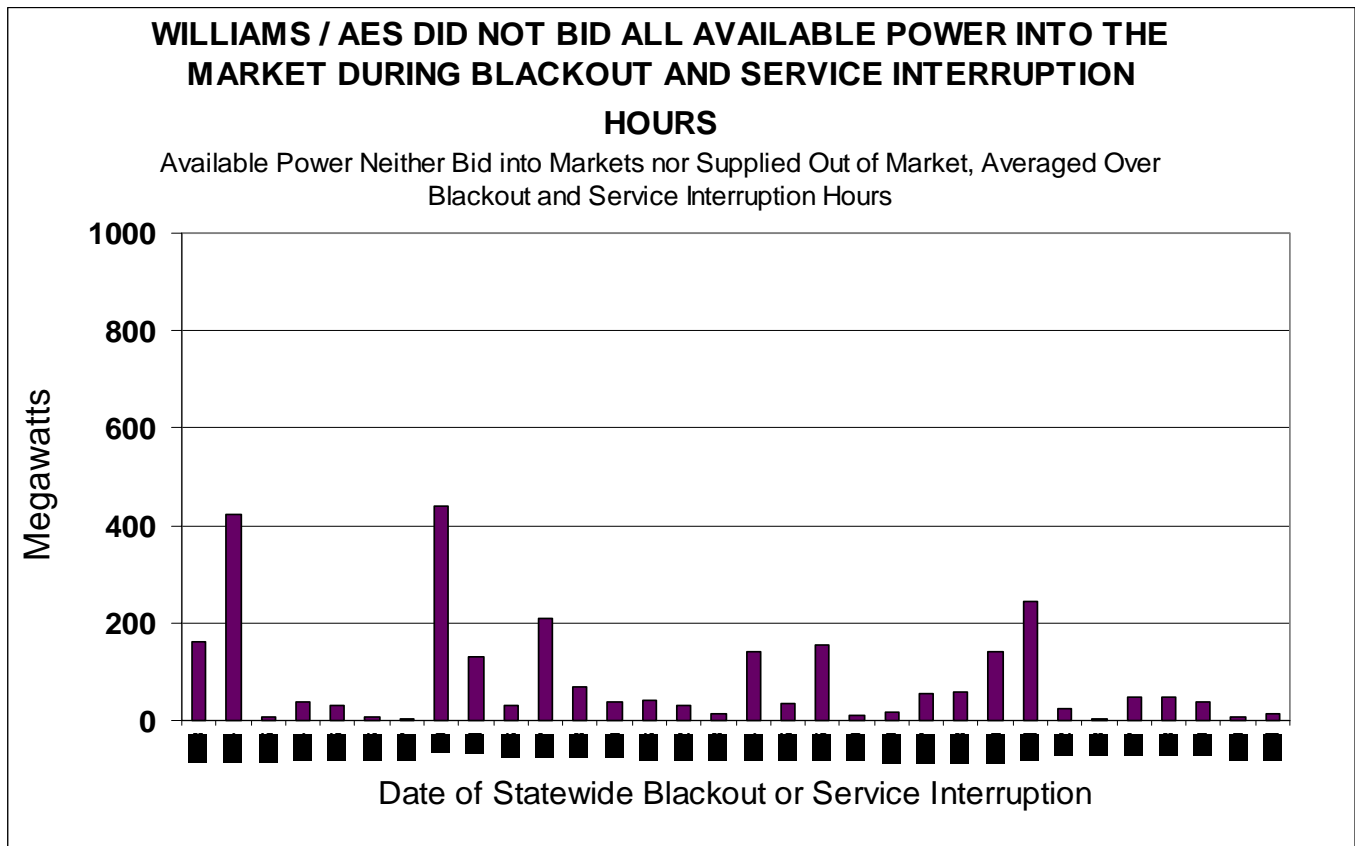
Figure 4.4 – Reliant



- Figure 4.4 shows that on November 13, 2000, Reliant had, on average, over 800 megawatts of available power that it did not bid into the ISO's real time market during service interruption hours. As noted above, a shortage of 1,857 megawatts caused service interruptions on that day. **Thus, by itself, Reliant did not bid available power into the market in an amount equivalent to nearly half of the service interruptions occurring on that day.**
- Figure 4.4 also shows that on May 31, 2001, Reliant had, on average, over 500 megawatts of capacity that it did not bid into the ISO's real time market during service interruption hours. Again as noted above, on that day, a shortage of 783 megawatts caused service interruptions. **Thus, by itself, Reliant did not bid available power into the market in an amount equivalent to nearly two-thirds of the service interruptions occurring on that day.**
- Figure 4.4 also shows that Reliant had, on average, between 200 and 600 megawatts of available power that it did not bid into the ISO's real time market during blackout and service interruption hours on an additional 16 of the 32

statewide blackout and service interruption days. **Thus, Reliant did not bid available power into the market in an amount equivalent to a substantial fraction of the service interruptions occurring on those 16 days.**

Figure 4.5 – Williams/AES



- Figure 4.5 shows that Williams/AES had, on average, over 100 megawatts of available power that it did not bid into the ISO's real time market during service interruption hours on nine of the 32 statewide service interruption days. **Thus, Williams/AES did not bid available power into the market in an amount equivalent to a significant fraction of the service interruptions occurring on those nine days.**

A comparison of Figures 3 through 3.5 and 4 through 4.5 shows that, on most days, the five generators failed to offer power to the ISO in amounts generally comparable to the shortages of megawatts that caused the blackouts or service interruptions. Although on some days there is no close correspondence between megawatts not generated and

megawatts not bid, Figures 3 and 4 show that on the majority of days, a close correspondence did exist between these two data sets. Therefore, it is reasonable to conclude that failure to bid was a major reason why the five generators did not generate all available power on the 32 statewide blackout and service interruptions days that occurred between November 2000 and May 2001.

Most Blackouts and Service Interruptions Could Have Been Avoided

Figures 3 through 3.5 demonstrate that the five generators did not generate all available power on the 32 statewide blackout and service interruption days that are the focus of this study. Figures 4 through 4.5 show that the five generators did not bid all available power into the ISO real-time markets on those days. The generators' failure to bid in and to generate all available power when it was most needed resulted in consequences. The Five Generators' failure to generate or bid in power directly contributed to the blackouts that Californians suffered during the energy crisis, as well as to the many unseasonable service interruptions that many California businesses had to endure. Specifically, the analysis shows that enough available power was available, but not generated, to avoid:

- **All 4 days of blackouts, including 100% of blackout hours in Southern California;**
- **3 of the 7 blackout days, including 65% of blackout hours in Northern California.**
- **81% of service interruption hours in the South, and 51% of service interruption hours in the North.**

Firm Customers in Southern California Suffered Unnecessary Blackouts

Figure 5 shows that 100% of the 16 blackout hours in Southern California could have been avoided if the generators in Southern California had generated all available power in that part of the state. Moreover, in every hour, substantial amounts of available but unused generation could have been sent to help alleviate blackouts in Northern California.

Figure 5

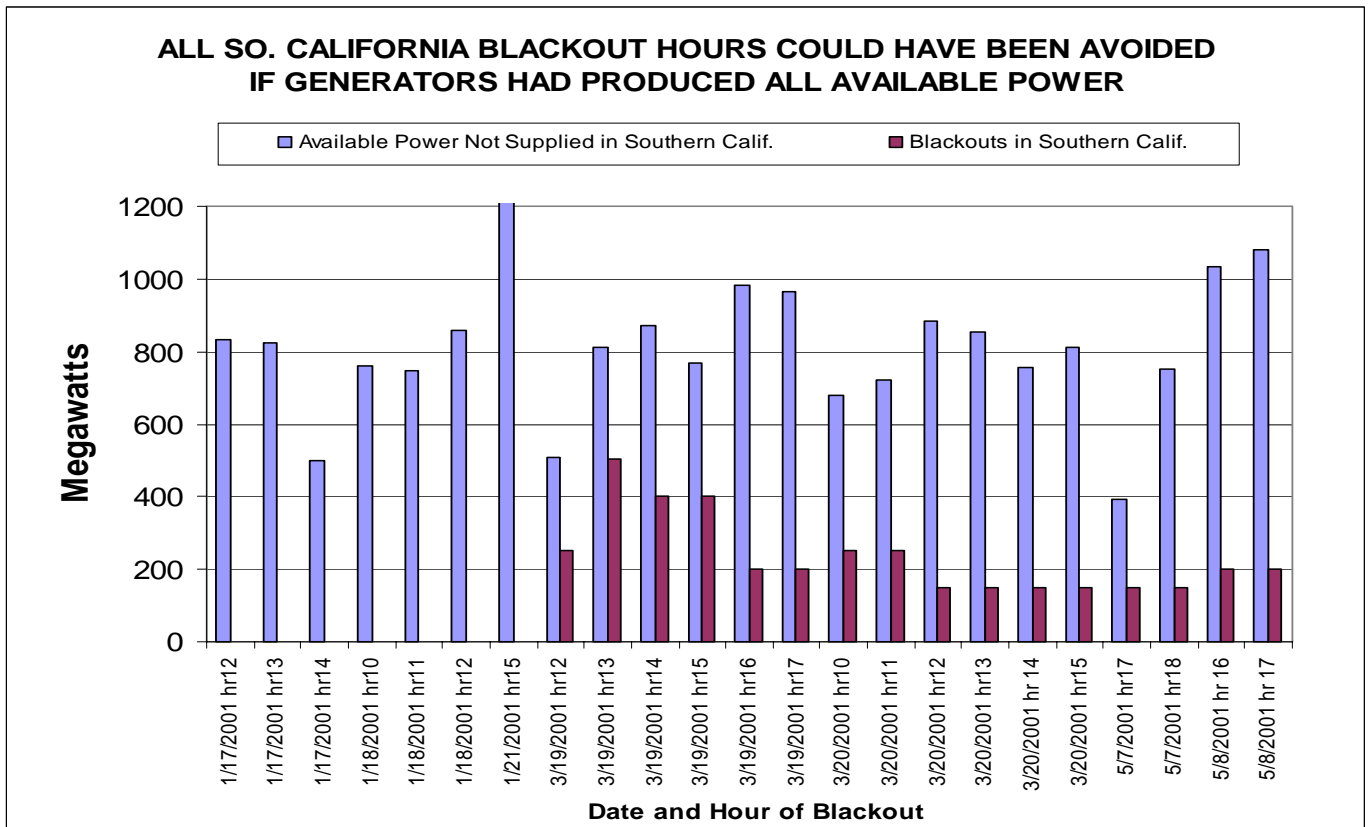


Figure 5 demonstrates that on March 19, 2001, firm electricity customers experienced between 200 and 500 megawatts of power blackouts between the hours of noon and 6 p.m. Examining the hour-by-hour data in Appendix A for each of these 6 hours, when considering only the three wholesale generators who operate exclusively in Southern California (Dynegy, Reliant and Williams/AES), these three companies, taken together, did not generate 423, 428, 441, 441, 431 and 501 megawatts in those six hours. Thus, in all but hour 13, electricity that these three generators alone could have provided would have prevented the blackouts. Moreover, when the available but unused power of Duke's two major Southern California plants is added, the power deficit that triggered the blackouts on March 19 disappears.

Analyzing the other three days of Southern California blackouts, the conclusion that these blackouts could have been avoided is even more compelling. Appendix A shows that there were never more than 252 megawatts of power blackouts in Southern California in any hour on March 20, May 7 or May 8, 2001. During the six blackout hours on March 20, excluding Duke, there were never less than 522 megawatts of available power not

generated by Dynegy, Reliant and Williams alone, and there were as many as 808 megawatts of available power not generated by those three generators in hour 13 on that day.

On May 7, when a shortage of 151 megawatts caused power blackouts, Dynegy, Reliant and Williams alone had 300 megawatts of available but unused power in hour 17 and 222 megawatts of available but unused power in hour 18. Moreover, Duke's plants in Southern California could have generated additional power, especially in hour 18.

Finally, on May 8, a shortage of 202 megawatts caused power blackouts in Southern California. Although Dynegy, Reliant and Williams alone could not have made up the deficit in hour 17 on that day, Duke's plants in Southern California could have generated more than 800 megawatts of additional power during both blackout hours on that day.

There can accordingly be no doubt that every hour of blackouts in Southern California could have been avoided if the plants owned by the five generators in Southern California had generated all available power. Moreover, the hour-by-hour data in Appendix A showing megawatts not bid by the five generators generally tracks the data on megawatts not generated. The five generators did not generate all available power from their Southern California plants during the blackout hours in Southern California. A major reason for this is that the five generators did not bid the power from those plants into the ISO's market.

Firm Customers in Northern California Suffered Unnecessary Blackouts

Nearly two-thirds of the blackout hours in Northern California could have been avoided if the five generators had produced all of their available power throughout the state, allowing power to move north over Path 15.

In comparison to Southern California, relatively little available but ungenerated power existed in Northern California during blackouts. The analysis concludes that only one of the seven Northern blackout days (May 7) and 9% of blackout hours could have been avoided solely with locally generated power. However, power was available that could have been generated in Southern California and sent north on those blackout days. Thus, Figure 5 shows that for 15 of the 16 statewide blackout hours in Northern California, excess Southern California generation could have mitigated the blackout in Northern

California,³² because the number of excess Southern California megawatts was significantly greater than the megawatt shortage experienced in Northern California.

For example, in Hour 14 of March 20, 2001, there was a shortage of 107 megawatts in Northern California, but there were 604 megawatts of available power not generated in Southern California. During that hour, Southern California did not need these 604 megawatts. This available but ungenerated power could presumably have been shipped to Northern California to help alleviate the power shortages there.

Crucial to an evaluation of the availability of excess Southern California power to mitigate blackouts in Northern California is the determination of how much additional power could have been moved on Path 15, which is a key element of the transmission link between Northern and Southern California.

Appendices B and C set forth the analysis of available power in California when Path 15 congestion is taken into consideration.

During the statewide blackouts of March and May 2001, the amount of excess capacity on Path 15 exceeded the amount of surplus ungenerated power in Southern California

that was available to alleviate the blackouts in Northern California. **Figure 6** compares, for each hour of blackout, the shortage of megawatts that caused blackouts of customers in Northern California to the amount of power that would have been available to avoid those blackouts had generators produced all available power throughout California. This latter quantity can be calculated as the sum of (1) the power available but not generated in Northern California, and (2) the surplus power in Southern California that could be transported North on Path 15.

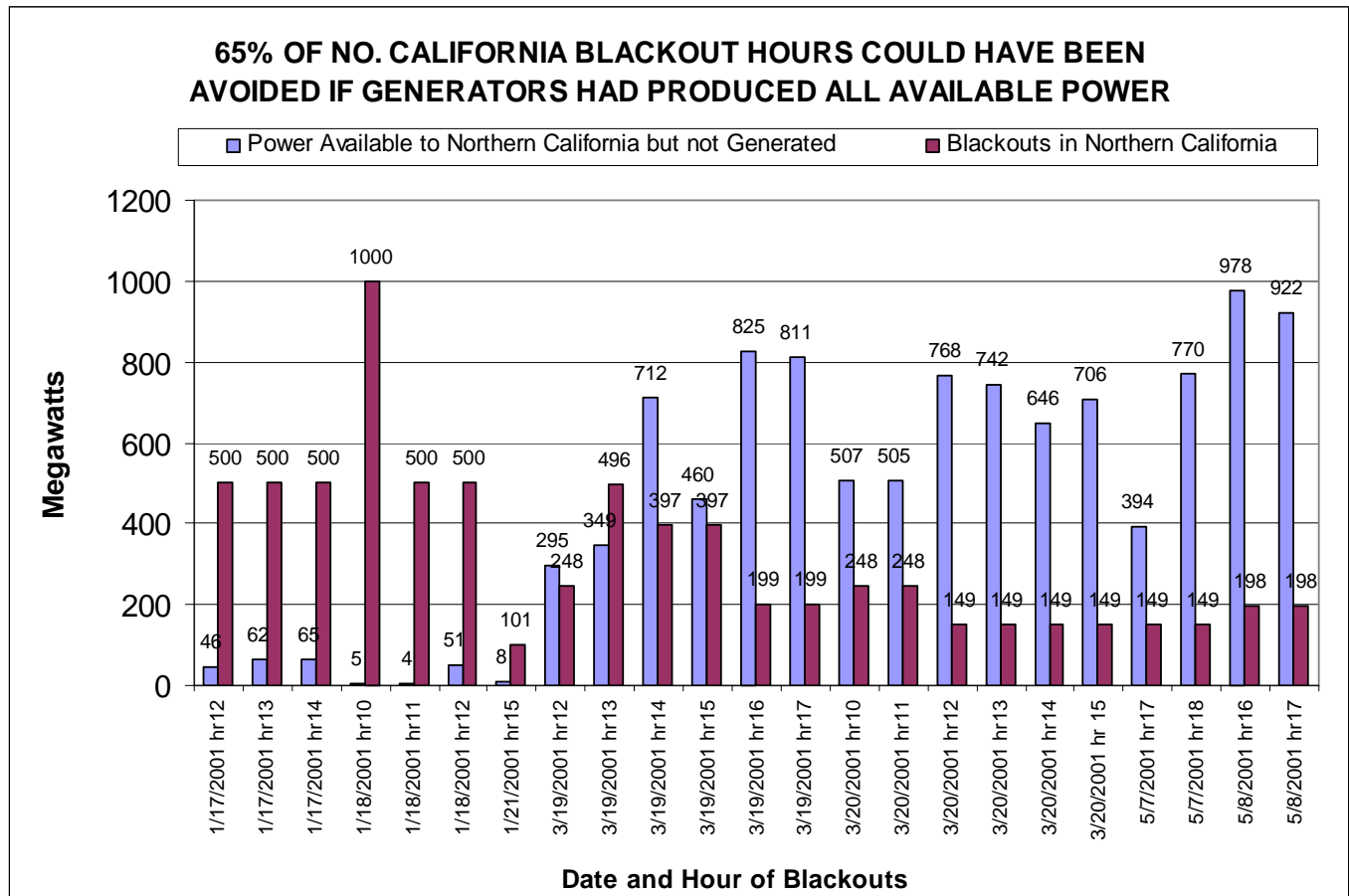
Figure 6 shows that three of the blackout days (March 20 and May 8) in Northern California could have been avoided, and the fourth blackout day in Northern California

Path 15 is the key link in the transmission system connecting Northern and Southern California. It allows power plants in Southern California to serve customers in Northern California and vice-versa, but sometimes Path 15 is full, or congested.

³² The exception is Hour 13 on March 19.

(March 19) could have been avoided in all but one hour had the five generators' excess ungenerated power in Southern California been made available.

Figure 6



During the three blackout days in January 2001 (which affected only Northern California), ISO data shows that Path 15 had little if any excess capacity.³³ Thus, even though substantial excess ungenerated power existed Southern California on those days, this power could not easily be moved to Northern California without exacerbating heavy flows on Path 15.

³³ WECC requires the ISO to keep flows on Path 15 below certain limits, and, if flows exceed those limits, to bring them below those limits within a few minutes. If these limits (which will vary depending on a number of factors, including temperature and the availability of other transmission lines) are exceeded, and both of two “contingencies” (that is, transmission or generation plant failures) occur on the electrical transmission system in Western United States, the worst-case scenario would present the danger of uncontrolled shutdowns throughout the West.

Thus, given the availability of excess capacity on Path 15 on the statewide blackout days that occurred in March and May of 2001, and given the simultaneous availability of additional but unused generating capacity in Southern California on those days, all but one of the blackout hours occurring in Northern California in March and May of 2001 could have been avoided.

Non-Firm Customers Were Unnecessarily Harmed by Service Interruptions

Power was interrupted to non-firm customers on all of the 32 statewide blackout and service interruption days documented in Figures 3 and 4. In addition, there were six additional days when service interruptions occurred only in Northern or Southern California, but not in both halves of the state. Although non-firm customers had agreed to be interrupted for as many as 150 hours per calendar year,³⁴ non-firm customers understood that such interruptions would be necessary, if at all, mostly in peak hours during the summer.

However, the ISO's repeated calls for interruption in January 2001 virtually exhausted all allowable hours in PG&E's service territory, and used half of the hours in Southern California.³⁵ Businesses on interruptible rates were forced to close down day after day,³⁶ sometimes multiple times each day, or pay substantial penalty fees for failing to comply with interruption requests. The penalty fees and the interruptions themselves caused substantial economic damage to those businesses, their employees and the state, and in some cases may have jeopardized public safety.³⁷ The CPUC accordingly suspended

³⁴ Under PG&E's interruptible program for large commercial and industrial customers, non-firm customers agreed to have their power interrupted for up to a total of 100 hours in the course of as many as 25 separate interruptions. Under SCE's similar program, non-firm customers agreed to have their power interrupted for up to a total of 150 hours in the course of as many as 32 separate interruptions.

³⁵ CPUC Energy Division, *Report on Interruptible Programs and Rotating Outages*, February 8, 2001, pp. 4-5. According to the ISO's outage log, in January alone, the ISO requested 104 hours of service interruption in PG&E's territory, and 101 hours in SCE's service territory. SDG&E's program is not discussed in detail here, as only 40 megawatts were available for interruption.

³⁶ Of the 38 days of non-firm service interruptions examined in this Report, nearly half occurred in four different periods of four successive days: December 4-7, 2000; January 16-19, 2001; February 12-15, 2001; and May 7-10, 2001.

³⁷ For example, in PG&E's service territory, "customers found it difficult to respond to repeated, frequent requests to curtail (sometimes two or three times per day for up to 6 hours each time) without jeopardizing their operations, and in some cases public safety." CPUC Energy Division, *op. cit.*

penalties for non-compliance with interruption orders on January 26,³⁸ and reworked the program to provide the flexibility needed to have non-firm load available during summer peak hours in 2001.

Appendices A, B and C provide data, on an hour-by-hour basis, for all of the hours of blackouts and service interruptions (for both firm and non-firm customers) in each part of the state, on all 38 days on which service was interrupted to customers of the utilities in part or all of the state,³⁹ and for which the CPUC has reliable generation data. The data contained in Appendix B allow conclusions to be reached about the extent to which service interruptions to non-firm customers could have been avoided, without overloading Path 15, had the five generators provided all available generation.

The data in Appendix A show, for each day of blackouts and service interruptions in each part of the state, the amount of power that was available but not generated during blackout or service interruption hours in that part of the state, and the amount of load shed during each hour. Further, using the methodology described in Chapter 2 above, along with data on Path 15 flows and limits, Appendix B shows which hours and days of service interruptions could have been avoided.

81% of service interruption hours in Southern California could have been avoided using available but ungenerated Southern California power.

The data in Appendices A & B demonstrate that on the 33 service interruption days in Southern California, if generators located in Southern California had generated all of their available power, 81% of service interruption hours could have been avoided entirely.

For Northern California, the figures in Appendices A and B show that 11 out of 37 service interruption days could have been completely avoided using both locally generated power and power transportable from Southern California over Path 15. In all, between 43% and 56% of Northern California service interruption hours could have been

³⁸ See CPUC Decision # D.01-01-056.

³⁹ As noted in footnote 7, there were 32 days of statewide blackouts and service interruptions, and six additional days on which there were blackouts and service interruptions in either Northern or Southern California, but not statewide.

avoided, depending on the amount of reserve margin assumed to be necessary on Path 15.⁴⁰

Plant Outages Affected Service

As noted in Chapter 2, the analysis on which this Report is based accepts at face value the claims of the five generators regarding plant outages and mechanical problems. No plant capacity was counted as available that any generator reported to the ISO as “out-of-service” as a source of power that was available but not bid or generated. Figure 2 shows that on all but two of the 32 statewide blackout and service interruption days that are the focus of this Report, there were at least 5,000 megawatts (more than 30%) of the Five Generators’ capacity (excluding 399 megawatts of peaking capacity) that was out-of-service. Moreover, there were over 6,000 megawatts (more than 36%) of this capacity out-of-service on six of these 32 days, over 7,000 megawatts (more than 42%) out-of-service on four additional days, and over 8,000 megawatts (nearly 50%) out-of service on December 7, 2000.

The rate of plant outages during the energy crisis was well above historical averages. The fact that between 30% and 50% of the plants owned by the five generators collectively were out-of-service on so many days during the energy crisis seems anomalous. Had the outage rate for these plants been consistent with historical averages (especially in Northern California, where the

The rate of plant outages during the energy crisis was well above historical averages.

data shows generating all available power alone would not have avoided some blackouts and service interruptions), more blackouts and service interruptions could have been avoided.

⁴⁰ As discussed in Chapter 2, three alternative safety margin estimates were used in calculating the available capacity on Path 15 in any given hour, 50, 200 and 600 megawatts. The choice among these three alternative safety margin estimates does not affect any of the conclusions discussed above with regard to avoidable firm outages or avoidable non-firm outages in Southern California. However, this choice will slightly affect the estimates of avoidable non-firm outages in Northern California. Assuming a safety margin of 200 megawatts on Path 15, 131 out of 257 service interruption hours, or 51%, could have been avoided. Assuming a more conservative safety margin of 600 megawatts on Path 15, 110 out of 257 service interruption hours, or 43%, could have been avoided. Assuming a less conservative safety margin of 50 megawatts on Path 15, 143 out of 257 service interruption hours, or 56%, could have been avoided. The data contained in Appendices B and C is based on the 200-megawatt safety margin.

Moreover, more than one study⁴¹ of the California electricity market suggests that strategic decisions by generators directly affect plant availability. For example, a generator can decide whether or not to maintain plants at a high level. Low-level maintenance (resulting in lower costs to the generator) can result in more frequent breakdowns. Also, the decision to declare a plant “out-of-service” on a given day can also be a matter of judgment about whether a given “problem” at a plant is serious enough to justify taking the plant out of service. Such strategic decisions can result in less plant availability, hence, in tighter electricity supplies and in higher prices and higher profits for the generators.

Well over 40% of the capacity of Mirant, Reliant and Williams/AES was either not available or not supplied to meet California’s energy needs during the crisis period.

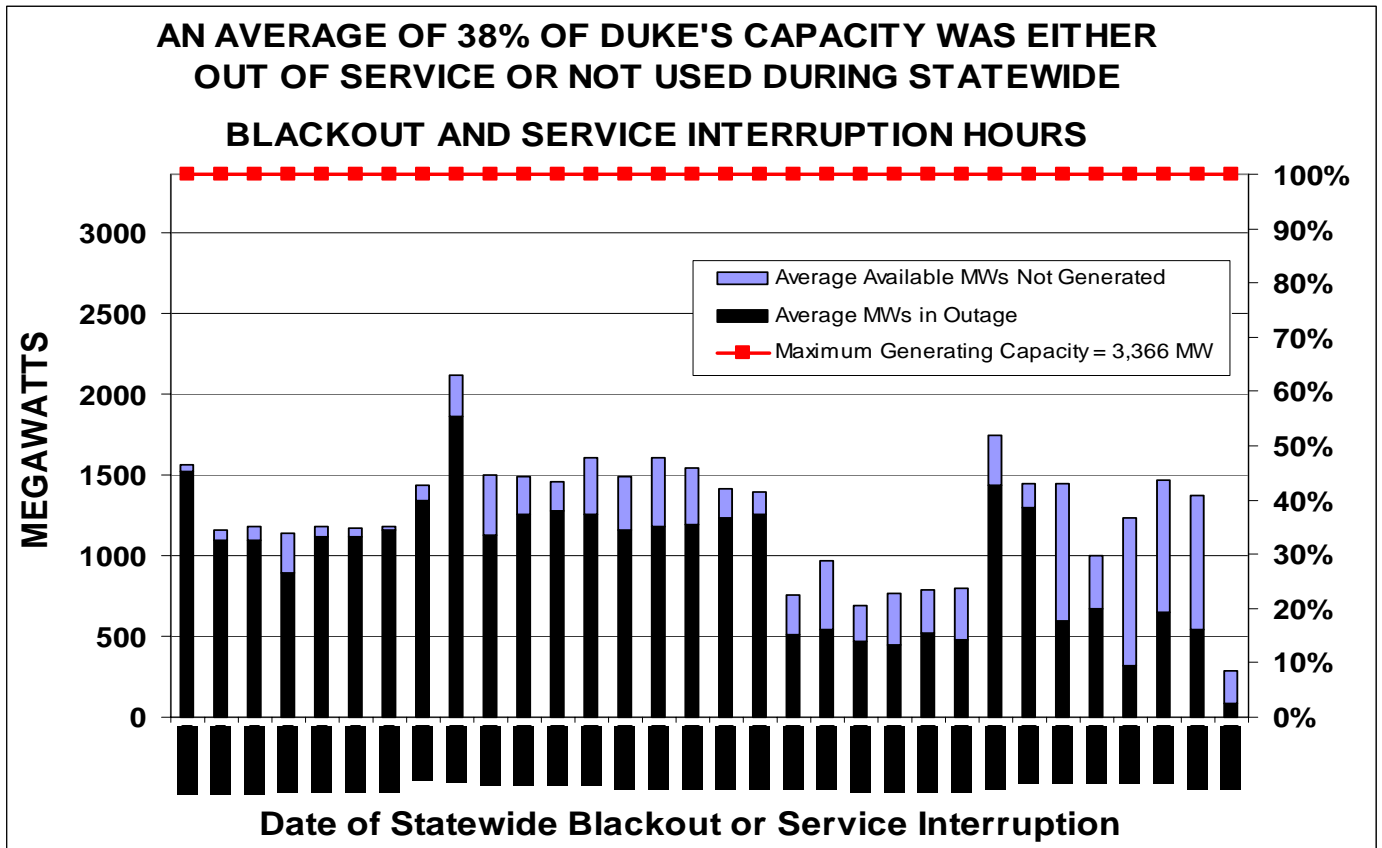
Although the analysis thus far has accepted the claims of the five generators regarding plant outages and mechanical problems, the plant outage data, as presented in Figure 2, is added together with the data on available power not generated presented in Figure 3 to develop composite data on the total amount of power either not available or not supplied on the 32 statewide blackout and service interruption days analyzed in this report. This composite data is presented, broken down on a generator-by-generator basis, in **Figures 7.1 through 7.5.**

Figures 7.1 through 7.5 show the maximum generating capacity for each of the five generators and compare this number to the sum of : (1) the average daily amount of megawatts of that generator’s capacity that was out-of-service on each of the 32 statewide blackout and service interruption days, and (2) the amount of available power that was not generated by that generator, as shown in Figure 3 and Figures 3.1 through 3.5.⁴²

⁴¹ Severin Borenstein, James Bushnell, Frank Wolak, *Diagnosing Market Power in California’s Restructured Wholesale Electricity Market, August 2000*; Joskow and Kahn, *Identifying the Exercise of Market Power: Refining the Estimates, July 5, 2001*

⁴² As is similarly noted in footnotes 27 and 31, the analysis presented in Figures 7.1 through 7.5 for **statewide** blackouts and service interruptions is nearly identical to the analysis of blackouts and service interruption affecting only one part of the state. An average of 5,866 megawatts were out-of-service during

Figure 7.1 – Duke



statewide blackouts and service interruptions, compared to 5,805 MW during **non-statewide** blackouts and service interruptions.

Figure 7.2 – Dynegy

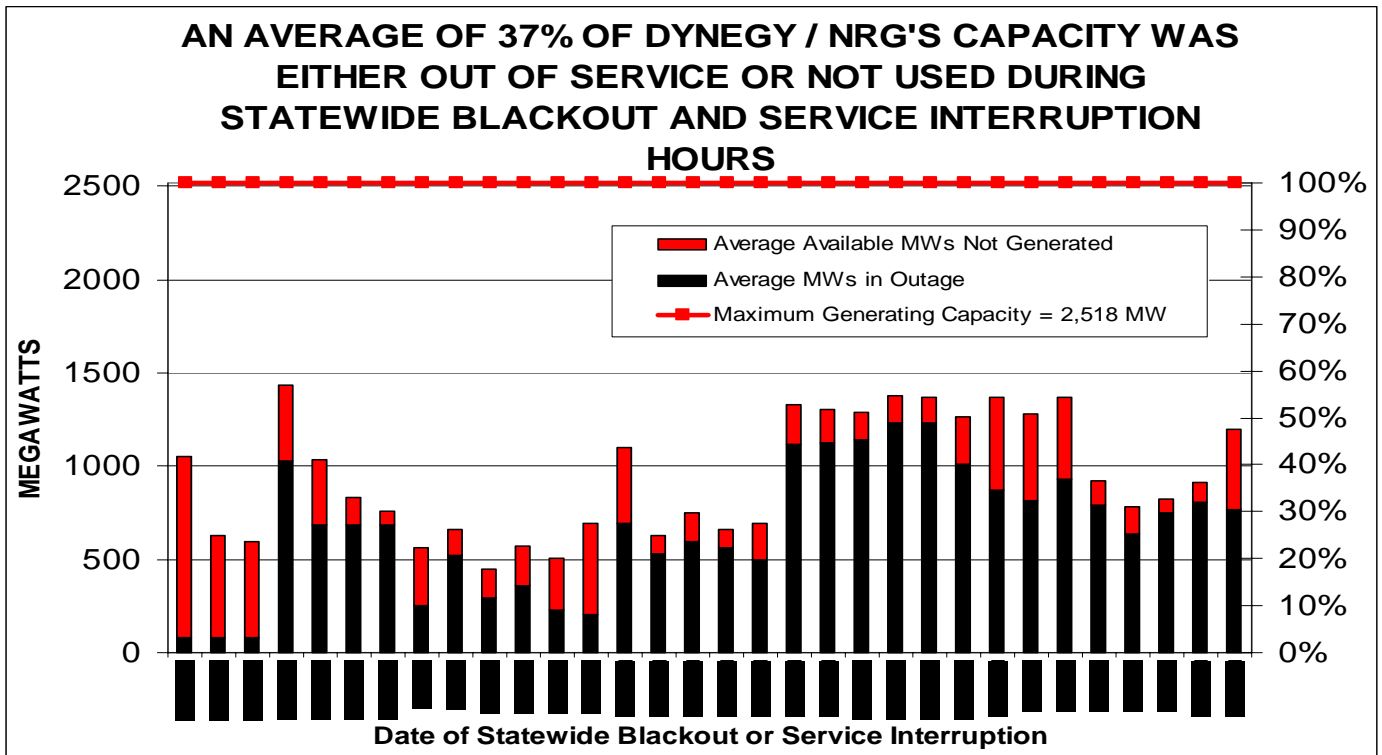


Figure 7.3 – Mirant

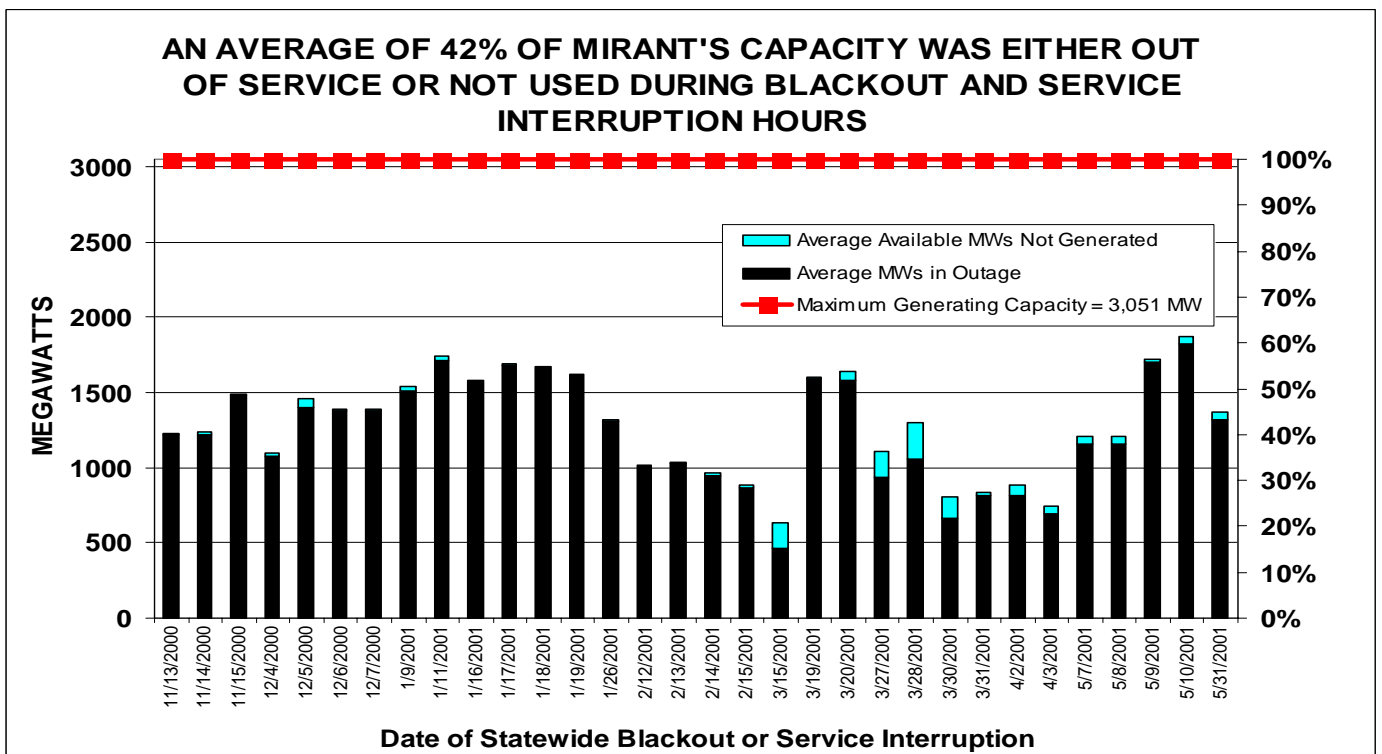


Figure 7.4 – Reliant

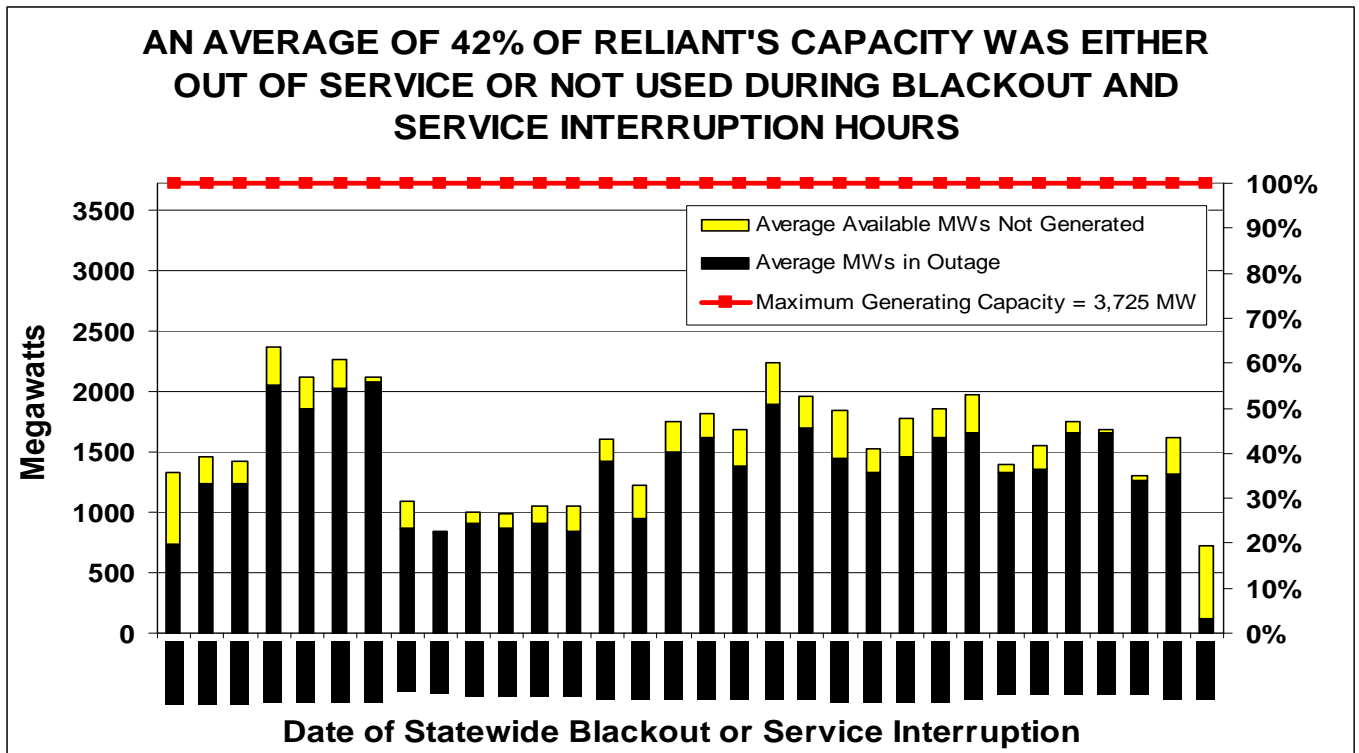
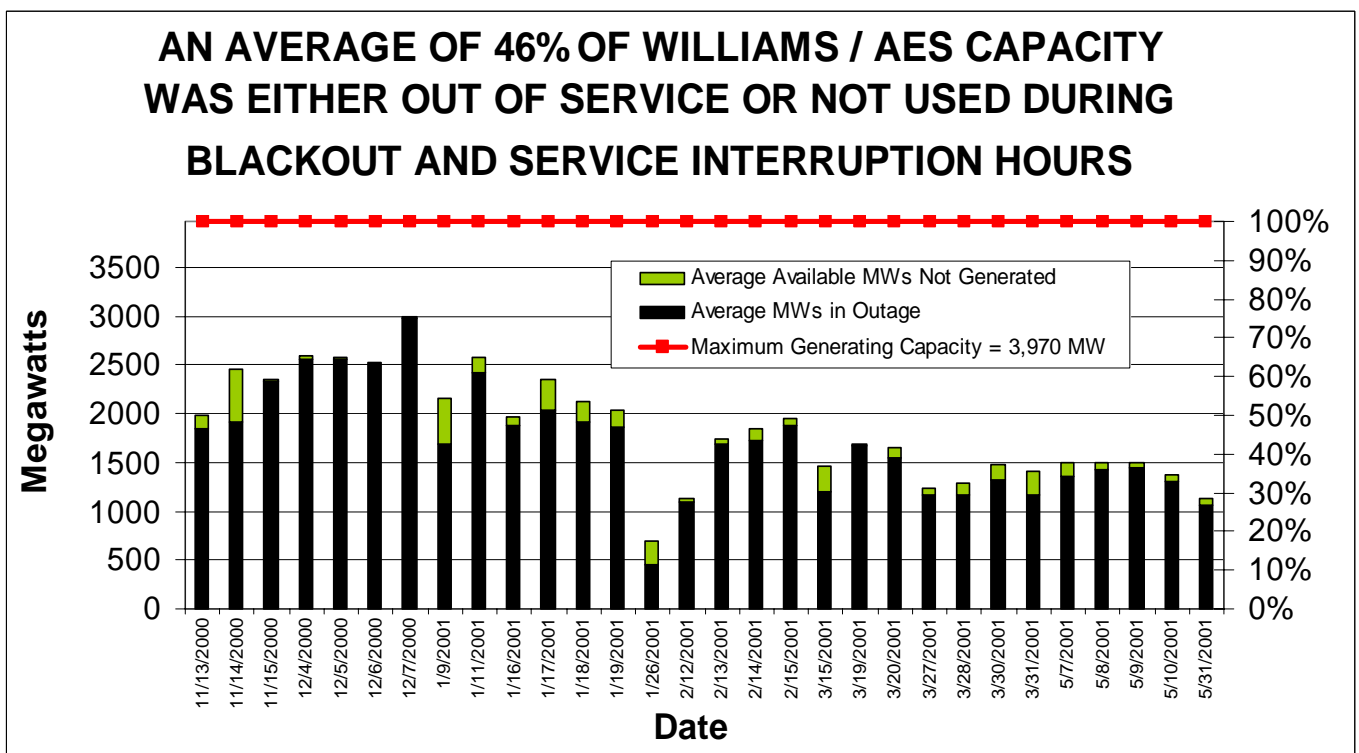


Figure 7.5 – Williams/AES



Figures 7.1 through 7.5 show that when data on plant outages is combined with data on available power not generated, between 36 and 46% of the generating capacity of the five generators was either not available, or not supplied, on the 32 statewide blackout and service interruption days that are the focus of this Report. Specifically,

- **37% of Dynegy’s capacity was either out of service or not made available;**
- **38% of Duke’s capacity was either out of service or not made available;**
- **42% of Reliant’s capacity was either out of service or not made available;**
- **42% of Mirant’s capacity was either out of service or not made available; and**
- **46% of Williams/AES’s capacity was either out of service or not made available.**

This report demonstrates that many blackouts and service interruptions could have been avoided if the five generators had generated all available power, but Figures 7.1 through 7.5 show that we cannot reach conclusions about the relative role of any generator in contributing to the crisis based on “megawatts not generated” alone. For example, the data show that although Mirant and Williams/AES supplied more of their available power than the other three generators, they had less available power. This was primarily because the plant outage rates for these two generators were high. Conversely, the data show that although Duke and Dynegy did not generate a larger number of megawatts than

Although Mirant and Williams/AES supplied more of their available power than the other three generators, their outage rates were so high that they used less of their installed capacity than the other three generators during statewide blackout and service interruption hours.

the other three generators, their plant outage rates were substantially lower than those of the other three generators, such that the total amount of their capacity that was either not available, or not supplied on the 32 statewide blackout and service interruption days

was actually somewhat lower than that of the other three generators.

Although this report concludes that most of the blackouts and service interruptions that California experienced between November 2000 and May 2001 were avoidable, the ultimate determination of the relative role of each of the five generators in contributing to blackouts and service interruptions cannot be made until a more detailed examination of plant outages has been completed.

Chapter 4

The Generators Bear Considerable Responsibility for Blackouts and Service Interruptions

As has been shown, the five generators bear considerable responsibility for the blackouts and service interruptions that occurred between November 2000 and May 2001. First, as Chapter 3 makes clear, they failed to bid in all available power supplies during blackouts and service interruptions when California desperately needed the power. Second, beyond failing to bid, there were many other strategies the five generators could and did use to withhold power under rules then current at the ISO. An examination of generation and bidding data, as well as plant and ISO logs, suggests that the generators did in fact use these strategies to withhold power in several instances.

The Evidence Suggests that Generators Withheld Power at Critical Times

Based on a review of logs maintained by the ISO and the individual generators, along with other data, this report presents a number of examples of behavior that provide additional evidence that one or more generators may have deliberately withheld power they could have generated during blackouts and service interruptions. The following examples do not identify the specific plant or the specific generator in question, because the ISO and plant logs from which they are taken were provided to the CPUC as confidential documents pursuant to a protective order.⁴³

Generators Failed to Follow ISO Dispatch Requests

At 3:58 p.m. on November 14, 2000, facing interruptions of service to non-firm customers, the ISO requested Generator A and other generators to “move all available units to full load.” At 5:15 p.m., with reserves at only 3%, the ISO was forced to interrupt roughly 1,400 megawatts of non-firm load through approximately 7 p.m. During power outage hours on that day, Generator A withheld over 500 megawatts of its

⁴³ The generators have insisted that the CPUC maintain this confidentiality by not identifying the names of any generators or plants in the discussion of this anecdotal data in this report. The generators initially resisted the CPUC’s efforts to use much of the data discussed in this report. In order to facilitate the resolution of this dispute, the CPUC agreed not to name the generators whose conduct is discussed in this chapter.

available generation, despite the fact that ISO databases show that the plant was in service at the time.

At 7:56 a.m. on May 8, 2001, operators at Plant B received an order from headquarters to start up the plant as requested by the ISO and relayed by the generator's headquarters. Eight minutes later, plant operators aborted start-up on orders from headquarters, who "would not accept all conditions of the plant's availability." Eleven minutes later (at 8:15 a.m.), the ISO declared a Stage 1 Emergency.

Generators Declined the ISO's Automated Dispatch Instructions

As discussed above, generators were permitted to decline automated instructions from the ISO, even though the instructions simply responded to bids submitted by the generators only minutes or hours earlier. Generators were required to supply a code to explain why they declined the instruction. In some cases, generators had good reason for declining the instruction, for example, if the plant had broken down after submitting bids. Generators often declined instructions, citing "economic considerations." Such declinations made no sense since the generator set bid price itself, and forced the ISO to find other supplies (if available) on very short notice, probably at a higher price.

During January 18, 2001 to February 16, 2001, California experienced a continuous Stage 3 Emergency, the most severe level. Nonetheless, the ISO's automated dispatch system database reflects that generators used "economic considerations" as an excuse to decline generation 262 times during this period.

Generators Failed to Take All Actions Necessary to Make Plants Available to the ISO as Soon as Possible After Outages

During emergencies, generators should have made every effort to make generation available to the ISO. On May 7, 2001, scheduling coordinator C failed to check whether a generating unit was available, and declined real-time dispatches totaling approximately 100 megawatts; at this time, the ISO blacked out 300 megawatts of power service around the state. According to the plant's logs, at 3:28 p.m., the plant informed its scheduling coordinator that the plant would return to service at 4:27 p.m. There is no record in the plant's logs of further discussions between the plant and the scheduling coordinator. At 4:37 p.m. and 4:44 p.m., the ISO dispatched approximately 100 megawatts, but the plant refused the dispatches due to the "unit [being] forced out." At 4:45 p.m., the ISO

ordered blackouts of 300 megawatts statewide. The plant did accept similar dispatches after 5:07 p.m., 37 minutes after the plant was supposedly available.

In another instance, according to ISO logs, on January 25, scheduling coordinator D informed the ISO that a unit was out of service. At 8:35 p.m. the next day, the plant log shows the plant was available to operate. According to the ISO log, scheduling coordinator D did not tell the ISO the plant was available until 5:15 p.m. on January 28, nearly two days after the completion of repairs. A continuous Stage 3 emergency was in effect throughout this period.

Generators Failed to Provide Adequate Fuel and Staffing for Plants

As a matter of course, plant operators should procure adequate fuel for plant operations. According to ISO logs, on December 7, 2000, at 2:32 p.m., plant E ran out of fuel. A Stage 2 emergency was in effect at that time; a Stage 3 emergency followed at 5:15 p.m. The plant got fuel and returned to service the next day, but it had to operate below capacity, allegedly because operating without adequate fuel had plugged fuel nozzles.

Plant operators should also have provided adequate staff to keep plants operating, and put plants on line rapidly when so requested by the ISO. At 12:11 p.m. on November 19, 2000, ISO logs show that the ISO's control operators ordered units to come on line the next day to maintain the reliability of the system. Generator F asked whether the ISO would pay for start-up costs. The ISO responded that the plants were needed for system reliability; questions about payment could be taken up later with the ISO's client representative who, unlike the ISO's control operators, was authorized to discuss payment issues. At 12:41 p.m., the ISO's control operator made a pointed entry in the ISO log:

“REFUSAL TO PLACE UNITS IN SERVICE

“[The Scheduling Coordinator] is refusing to place [the units] in service as ordered pursuant to [ISO] Tariff provision 6.5.2. It was explained to [the scheduling coordinator] that the CAISO is in a Stage 1 Emergency at this time, and anticipates being in an Emergency situation tomorrow. [The Scheduling Coordinator] also reports that they will not pursue manpower issues until they verify the method of payment. They are demanding that their client representative be contacted before any further [sic] take any steps to bring the unit on. Further, they explained that it is a

supply vs. demand issue and the CAISO should reduce it's [sic] demand to make the system reliable."

It appears that generator F was advising the ISO to shed load to avoid starting up the plant. The ISO logs show that at 1:05 p.m., the generator declared the plants out of service due to lack of staff, and that the plants did not come back on line until December 5, 2000, more than two weeks later. The ISO in fact declared Stage 1 and 2 emergencies as expected on November 20, 2000. and again on December 4, 2000.

Similarly, ISO logs show that on January 5, 2001, generator G called the ISO to report that several of its units could not be available over the weekend on a four-hour notice, because all of the operators were either sick or on vacation. The ISO told scheduling coordinator G that the plants had to operate at 55 megawatts that weekend, either on a four-hour notice or with longer notice between 7 a.m. and 10 pm. Generator G responded that the plants would not be available that weekend.

Generators Improperly Argued With ISO Operators Over Price and Terms

On a number of occasions, generators impeded ISO operations and pressured the ISO by arguing about price with the ISO's system operators. These operators were responsible for balancing hundreds of power sources with the demand for power. Especially in emergency periods, they were very busy. Under emergency conditions, the ISO is empowered to specify the output of any generating unit in its territory. Prices are supposed to be worked out later under the provisions of the ISO's tariff.⁴⁴ ISO operators repeatedly informed generators that they had no authority to negotiate price, that generators were obligated to follow ISO instructions when system reliability was at stake, and that they should contact the ISO's client representatives to set a price for the power. One example, on November 19, 2000, appears above.

According to ISO logs, in two conversations beginning at 9:21 p.m. on December 6, 2000, the ISO ordered generator H to start three units with a total capacity of 580 megawatts for system reliability. Generator H refused to start the units up unless the ISO operators guaranteed a price; the ISO insisted that the plants were needed for system

⁴⁴ DOE's Emergency Orders recognized this principle. The first of those orders referred disputes about prices and terms to the Secretary of Energy. The Secretary was to immediately settle disputes about "conditions of service," while disputes about prices would be referred to the FERC for "determination at a later date." Subsequent orders used different language to the same effect.

reliability. Generator H called back minutes later to report that the plants were simply unavailable due to air quality restrictions.

Beyond Failure to Bid, Other Strategies Allowed Withholding

Beyond failing to bid all available power into real-time markets, generators could withhold power using other strategies, including: (1) inaccurately reporting that generating capacity was out-of-service and therefore unavailable; (2) withholding bids from day-ahead or hour-ahead markets, or declining to fulfill bids once made; or (3) pressuring the ISO outside of normal market procedures when conditions were desperate.

Inaccurate Plant Outage Reporting and Delays in Repairs Translate Into Withholding

Generators could inaccurately report to the ISO about the amount of power available to the system. By doing so, they could withhold such plants from the California market, since the ISO did not attempt to dispatch capacity that was reported to be unavailable. Generators could also withhold capacity by making repairs slowly, delaying notification to the ISO that repairs were complete, failing to staff plants adequately (as described above), or by failing to maintain adequate communications between the generator's headquarters and plant operators.

Withholding Bids From Day-Ahead and Hour-Ahead Electricity Markets, Declining to Fulfill Bids or Disregarding ISO Processes Destabilizes the System

The ISO's, and prior to February 2001, the PX's, market systems provided many opportunities to withhold power. The ISO was supposed to receive power through a number of computerized markets: the PX day-ahead markets, the PX hour-ahead markets (bids were due two hours before power was to be made available), and so-called real-time markets (bids due 45 minutes before each hour). The ISO dispatched real-time bids as needed during the operating hour, but generators could "decline" such dispatches. There was no guarantee that generators would supply power, even for accepted bids. Starting in December 2000, the ISO applied monetary penalties for failing to follow dispatch instructions. However, the monetary penalty may not have been sufficient to deter such refusals. In short, generators could fail to bid into day-ahead or hour-ahead markets at the ISO or the PX, delay bids as long as possible to pressure the ISO, decline ISO dispatches of real-time bids, or fail to generate as instructed by the ISO, all resulting in the withholding of power when needed.

The ISO could order generation from generators with “Regulatory-Must-Run” (RMR) contracts. The ISO could also negotiate “out-of-market” deals, sometimes at very high prices. Finally, the ISO could declare an emergency and order any plants in its service territory to generate power although generators were not obligated to comply where generation would violate state or federal law. In all cases, generators could raise legal objections to ISO orders, and those objections could not be resolved quickly. Disregarding these orders or refusing to enter into out-of-market contracts all contributed to power shortages and the destabilization of California’s electric power system.

Generators Failed to Bid in All Supplies During Blackout and Service Interruption Hours Even Though the Power Was Needed

The five generators knew that there was a desperate need for their power during blackouts and service interruptions. During the crisis, service interruptions burdened some or all non-firm business customers on 38 separate days. Some California businesses were forced to shut down for many days. In addition, there were four days of statewide blackouts and three additional days of blackouts in Northern California. During these blackouts, approximately 30% of California homes (and in Northern California, practically all that were not located on the same circuits as “essential” customers⁴⁵) lost power.

Generators may posit a number of possible reasons why a given generator may not have generated power on a given day.

- (1) It may be that the generator’s scheduling coordinator simply chose not to bid power in to the market on that day, citing economic considerations or giving other reasons. The ISO’s rules did not require generators to bid in their available capacity until the FERC’s “must offer” requirement was imposed on June 19, 2001.
- (2) The scheduling coordinator may have bid in the power, but the ISO may not have accepted or used the bid.

⁴⁵ “Essential” customers include large hospitals and police and navigation facilities. Circuits with such customers were exempt from blackouts.

- (3) It is also possible that a given generator failed to generate in accordance with ISO instructions on a given day even after the ISO had accepted that generator's bid or bids.

None of these reasons provides any justification or excuse for the failure of the five generators to bid in all available power.

- (1) In view of the crisis the state was facing, the generators' failure to bid raises urgent questions about regulation that depends largely on markets to assure the reliability of electric service.
- (2) Given the unprecedented nature and enormity of the energy crisis, it is likely that there were lapses and/or failures in the ISO's management of the transmission grid during the crisis. For example, the ISO may have failed to dispatch some available bids. But by not bidding all available power, the generators made it impossible for the ISO to dispatch all available supplies, except through last-minute out-of-market deals in which the ISO paid exorbitant prices under duress.
- (3) At base, a generator's failure to generate as much power as the ISO asks for is inexcusable in a crisis situation. Although the generation of power in excess of the ISO's request did sometimes help meet load, all such deviations from ISO requests, both positive and negative, interfered with the ISO's ability to monitor and manage the grid.

Chapter 5

This Report Correlates California's Energy Crisis To Real Time Generation and Bidding Data

Previous Studies Have Found Evidence Suggesting That Power Producers Restricted Output in Order to Raise Prices

California's restructured energy market has been the subject of other technical and economic studies. These studies provide substantial evidence that the generators examined in this report have exercised market power.

All studies of California's restructured electricity market that attempt to measure the exercise of market power have found empirical evidence that, at various times, power producers restricted output in order to raise prices, especially when demand was high and/or supplies were low. These studies all assume, as one author states, that "the ability to affect the price of electrical energy depends fundamentally upon the generation capacities and the costs of the various suppliers."⁴⁶

Using standard economic theory and relying on the best data available find on the operating characteristics and utilization of California's power plants, the studies estimate the costs of a competitive market where prices are set by costs of the least efficient plant operating at any one time.⁴⁷ Studies compare this perfectly or "workably" competitive "benchmark" to market prices, actual or simulated. While the data available were sometimes imperfect, and whereas some of these studies relied on limited public data,⁴⁸ these analyses specifically account for changes in the cost of natural gas and air pollution

⁴⁶ Severin Borenstein and James Bushnell, *An Empirical Analysis of the Potential for Market Power in California's Electricity Industry*, December 1988, Working Paper for the University of California Institute, Berkeley, CA, p.6.

⁴⁷ The least efficient plant operating sets prices, because in a competitive market, producers have strong incentives to use the cheapest plants first, using the more expensive plants only when necessary.

⁴⁸ In particular until the winter of 2000, no data was released publicly on which units were out-of-service day-by-day, and there remains no data in the public domain hour-by-hour. All the public data show is that the plants did not operate. As Joskow and Kahn observe, however, a statement by an owner that a plant is unavailable does not prove the point: "While it is impossible to prove that any given generating unit declared as a forced outage could have been available, the incentive to withhold is powerful and the observed behavior exceeds historic outage norms." Paul Joskow (Massachusetts Institute of Technology) and Edward Kahn (Analysis Group/Economics, San Francisco), *Identifying the Exercise of Market Power: Refining the Estimates*, July 5, 2001.

credits, two of the traditionally most expensive components of electricity prices. If anything, these studies understate the extent of market power, because they depend in part on published indices of natural gas costs as delivered to California. These indices, as we discuss further below, may have been manipulated during the crisis.⁴⁹ Finally, at least one of the studies⁵⁰ specifically identifies plants that did not run, even though their costs could have been fully paid at then-current market prices.

Electricity markets are subject to monopoly power⁵¹ because electricity cannot be stored, the number of plants at any one time is fixed, and consumers (at least in the short run) can make only moderate cuts in their usage in response to prices.⁵² Therefore, small supply decreases can cause very large price increases; so each entity with significant market share has an incentive to unilaterally raise market prices by restricting its own output. A number of factors can increase prices even higher: collusion between firms (either explicit or tacit), flawed market rules, and over-dependence on spot markets.⁵³

In 1998, as the ISO was starting operations, Borenstein and Bushnell used a simulation to show that, even without collusion between firms, power producers could restrict production and drive prices anywhere from 2 to 33 times competitive levels, depending on the time of year.⁵⁴ The simulations did not anticipate all the characteristics of

⁴⁹ In addition, El Paso natural gas pipeline used its control of pipeline capacity to Southern California to increase the price of gas delivered to the Southern California border. See, FERC Docket No. RP00-241-000. Of course, generators may have used long-term, fixed-price gas contracts to generate power for California, thereby avoiding the high spot prices assumed in these studies.

⁵⁰ Joskow and Kahn, pp.14-16.

⁵¹ The long-used “Cournot” analysis of monopoly argues that a firm that faces competitors whose production is fixed (in the case of a monopoly, that fixed production equals zero) can increase profits by restricting production and raising prices, as long as the price elasticity of demand (see footnote 52) is less than 1.0. Until that point, the additional profit from raising prices outpaces the profit lost through reduced volumes. The studies use various approaches to adapt this analysis to a market where many firms have market power and the individual incentive to use it.

⁵² This last factor, the elasticity of demand, is important to the exercise of market power. If customers have relatively low elasticity of demand (that is, they cut back usage very little in response to price increases), then firms with market power can raise prices much higher. Especially in the short run (before the consumer has a chance, say, to buy more efficient home appliances), electric consumers have a low elasticity of demand.

⁵³ Long term contracts with producers with market power reduce a consumer’s exposure to price changes in the short run. If contract prices are fixed, producers will get less revenue when they raise prices. However, those long-term contracts lock in any market power that exists at the time of signing.

⁵⁴ Borenstein and Bushnell, p.3 and Figure 3, showing results at an elasticity of 0.1.

California's market;⁵⁵ however, as Borenstein later put it, "while the exact degree of market power is an empirical question, a reasonable first cut analysis leads one to ask why a seller with 3,000-4,000 MW of capacity *wouldn't* exercise market power."⁵⁶

Since then, study after study has found evidence that suppliers took advantage of their power to raise prices, even more so beginning in May 2000. Borenstein, Bushnell, and Wolak have estimated a 16% increase in costs from June 1998 to September 1999.⁵⁷ Hildebrand, at the ISO's Department of Market Analysis (DMA) found from confidential ISO data that 30% of the ISO's energy costs were due to market power between May 2000 and March 2001.⁵⁸

Similarly, the ISO's Market Surveillance Committee, which reports to FERC and uses confidential data, repeatedly found that markets "have not been workably competitive."⁵⁹ Puller has found that firms fully exploited their individual market power from 1998 onwards; in 2000, prices were even higher than that, though not as high as a perfect cartel – that is, one acting as a single monopolist – could achieve.⁶⁰ In several papers analyzing the market through the summer of 2000, Joskow and Kahn also have found that prices rose above competitive levels; further, they identified individual plants that could have

⁵⁵ For example, the study assumes that new firms in the market would act competitively, while the big utilities (PG&E, SCE, and SDG&E) would have acted uncompetitively. However, because the report assumed that hydro and nuclear plants would produce as they would in a competitive market, the remaining MW owned by the three utilities were only 2,218, 4,296, and 1,875 MW respectively; mostly less than the MW owned by major independent scheduling coordinators today. Borenstein and Bushnell, p. 26.

⁵⁶ Severin Borenstein, *The Trouble With Electricity Markets and California's Electricity Restructuring Disaster*, PWP –081, U of CA Energy Institute, September 10, 2001, p. 21.

⁵⁷ Severin Borenstein, James Bushnell, Frank Wolak, *Diagnosing Market Power in California's Restructured Wholesale Electricity Market*, August 2000.

⁵⁸ Eric Hildebrandt, Ph.D., Department of Market Analysis, California Independent System Operator Corporation, *Further Analyses of the Exercise and Cost Impacts of Market Power in California's Wholesale Energy Market*, March 2001, p. 2. The methodology is described on p. 6.

⁵⁹ Market Surveillance Committee of the California Independent System Operator (Frank Wolak, Robert Nordhaus, and Carl Shapiro), *The Competitiveness of the California Energy and Ancillary Services Markets*, March 9, 2000; *An Analysis of the June 2000 Price Spikes in the California ISO's Energy and Ancillary Services Markets*, September 6, 2000; "Statement of Frank Wolak ...Before the Senate Committee on Commerce, Science, and Transportation," May 15, 2002, p. 5.

⁶⁰ Steven L. Puller, University of California Energy Institute, Berkeley, California, *Pricing and Firm Conduct in California's Deregulated Electricity Market* (PWP-080), November 2001. See abstract, p. 22, and pp. 36-37.

recovered all costs at current market prices but did not.⁶¹ In an updated paper, Borenstein, Bushnell and Wolak found that nearly 60% of the increase in electricity prices during the summer of 2000 was due to the exercise of market power.⁶² Finally, Sheffrin, director of the DMA, analyzed bids submitted by the “five large in-state generation owners”⁶³ and found that, between May and November 2000, those generators withheld bids from the real-time market 30% of the time, and submitted bids priced higher than their generation costs 60% of the time.

Economic studies that demonstrate evidence of exercise of market power by generators have been criticized from a number of perspectives. Most prominent among the various critiques are papers by Harvey and Hogan,⁶⁴ which challenge various assumptions and suggest some sensitivity analyses that they argue could change Joskow and Kahn’s results. Hogan and Harvey conclude that “it is impossible to prove the absence of any withholding or any exercise of market power without analyzing the reasons for every outage de-rating, and decision not to operate by every supplier,”⁶⁵ in addition to other data. As Joskow and

Documents recently released by Enron and Perot Systems Corporation show that various parties in the California market attempted to exploit the weakness of the ISO’s systems.

⁶¹ Paul Joskow (Massachusetts Institute of Technology) and Edward Kahn (Analysis Group/Economics, San Francisco, CA), *A Quantitative Analysis of Pricing Behavior in California’s Wholesale Electricity Market During Summer 2000: The Final Word*, February 4, 2002; Joskow, *California’s Electricity Crisis*, September 28, 2001; Joskow and Kahn, *Identifying the Exercise of Market Power: Refining the Estimates*, July 5, 2001. Not reviewed was the first paper in this series: Joskow and Kahn, *A Quantitative Analysis of Pricing Behavior in California’s Wholesale Electricity Market During Summer 2000*, NBER Working Paper 8157, March 2001.

⁶² Borenstein, Bushnell and Wolak, *Measuring Market Inefficiencies in California’s Restructured Wholesale Electricity Market*, University of California Energy Institute, CSEM WP 109, June 2002.

⁶³ As well as 16 importers in to California; Anjali Sheffrin, Ph.D., Director, Department of Market Analysis, California Independent System Operator, *Empirical Evidence of Strategic Bidding in California Real Time Market*, March 21, 2001, pp. 7-8. The ISO does not identify the five generators studied.

⁶⁴ We reviewed Scott M Harvey (LEGC, LLC, Cambridge, Massachusetts) and William W. Hogan, *Identifying the Exercise of Market Power in California*, December 28, 2001, the last of three papers in part replying to Joskow and Kahn. Harvey and Hogan’s long list of consulting clients includes three California generators, Mirant, Reliant, and Williams.

⁶⁵ Harvey and Hogan, p. 80.

Kahn point out, “Harvey and Hogan’s papers raise ‘questions’ and identify ‘uncertainties’ but do not put them together to come up with alternative estimates.”⁶⁶

Documents recently released by Enron and Perot Systems Corporation,⁶⁷ and a study of those documents by Dr. Robert McCullough,⁶⁸ show that various parties in the California market attempted to exploit the weakness of the ISO’s systems. Perot Systems prepared a briefing instructing companies how to exploit flaws in the ISO system for profit before the ISO could discover and correct the error. Enron, which apparently had significant control over transmission lines into California, also “gamed” the system, as corporate memos show. Thus, the potential for simultaneous withholding and gaming (including strategies not yet revealed) is very serious, and probably accounts for a large part of the rapid increase in costs in California during the crisis.

Finally, in August 2002, a FERC staff report finds specific instances of possible misconduct by Enron and other participants in Western energy markets. While the report is couched in tentative language, and covers only Enron and associated companies, it can be read as raising the possibility that deceit and deception were at the very core of energy trading during the crisis. As the report concludes, “many of Enron’s trading strategies may have been attempts to manipulate prices.” These strategies “may have involved deceit, including the submission of false information, including false schedules.” Moreover, the FERC report also finds “preliminary indications” that Enron and others may have manipulated published indexes of California gas costs (presumably used in the studies discussed above), so that those indexes did not reflect the generators’ actual costs during the crisis.⁶⁹ The FERC report also observes that “Enron traders took significant positions in [western natural gas] markets...and Enron’s activity coincides with the greatest volatility of electricity prices in California.”⁷⁰

⁶⁶ Joskow and Kahn, *The Final Word*, p. 34, footnote 42; see also *Refining the Estimates*, p. 3.

⁶⁷ Available at <http://www.perotsystems.com/>

⁶⁸ Robert McCullough, *Congestion Manipulation in California*, McCullough Research, June 5, 2002.

⁶⁹ Staff of the Federal Energy Regulatory Commission, *Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data, and Enron Trading Strategies; Fact-Finding Investigation of Potential Manipulation of Electric and Gas Prices*, Docket No. PA02-2-000, p. 4-5.

⁷⁰ *Ibid.*, p.52.

Chapter 6

FERC Must Act To Prevent Future Artificial Electricity Shortages in California

In an Order it issued on July 17, 2002, FERC continues to deny that California's energy crisis was caused by the generators' market power and gaming of the California electricity market. FERC's Order continues to underestimate and overlook the numerous actions taken by California and by Californians to solve its energy problems, including but not limited to the dramatic public response to calls for energy conservation during the summer of 2001.

FERC's Order continues to advocate allowing electricity prices to rise to reduce demand instead of solving the underlying market power problem. In advocating such approaches, FERC ignores its duty under the Federal Power Act to ensure that electric power prices are "just and reasonable." Rather, FERC's Order serves the generators' interests at the expense of the public that FERC was established to serve. FERC should stop protecting the foxes. It should stick to its mission and guard the henhouse.

FERC Must Take Stronger Action to Assure Market Stability

Significant reforms are needed in order to prevent future artificial energy shortages in California. Some of the most important of these needed reforms are within FERC's authority. These include reforming the ISO's tariffs and procedures through proposals currently before the FERC, requiring the generators to bid into California electricity markets and capping electricity prices in the Western United States.

The FERC partially addressed these issues in its July 17, 2002 Order. However, the actions taken by FERC in its July 17 Order are not sufficient to safeguard consumers from generator abuses that could produce exorbitant electricity prices. FERC must take stronger action to eliminate market manipulation from the ISO market. The following reforms are necessary:

FERC Must Continue to Require Generators to Bid In All Available Power

In its July 17, 2002 Order, the FERC extended the “must offer” obligation. However, the FERC did not make this obligation permanent, nor did FERC specify any means of enforcing this obligation. FERC’s “must offer” obligation must be made permanent and enforceable. Permanent implementation and vigorous enforcement of the “must-offer” obligation would prevent future abuses by requiring generators to bid all of their available power into the ISO markets.

As this report has shown, the failure of the five generators to generate and to bid into the ISO markets directly contributed to the blackouts and service interruptions that California experienced during the 2000 – 2001 energy crisis. Such artificial shortages must never again be allowed to occur.

FERC Must Set Reasonable Price Caps

One of FERC’s actions on July 17, 2002 was to raise the existing price cap for electricity in California from \$91 to \$250 per megawatt-hour. This new price cap was imposed without any justification. It is grossly higher than the operating cost of even the least efficient generator, based on current prices for natural gas. Given the market power that generators have in California, it is obvious that the lack of a reasonable price cap may well lead to unjust and unreasonable electricity prices for consumers. Thus, price caps must remain in place, at least for the time being, and FERC must revoke its enormous and unjustified increase in the current California price cap.

FERC Must Redesign the Market Operations of the ISO in Order to Reduce Gaming and Market Manipulation

On May 1, 2002, the ISO filed at FERC a Comprehensive Market Design Proposal (MD02) to help remedy the flaws in the ISO’s markets.⁷¹ These flaws contributed significantly to the energy shortages and price spikes that took place during the 2000 – 2001 energy crisis.

MD02 is subject to FERC’s approval. FERC should adopt the final MD02’s proposals that California filed with FERC in order to create stable, functioning electricity markets that provide just and reasonable rates. On the other hand, FERC’s disregard of the MD02

⁷¹ The ISO filed MD02 pursuant to FERC’s order of December 19, 2001 (see, 97 FERC 61,275.).

proposals as filed by California would exacerbate the existing difficulties in California and the rest of the Western United States.

In redesigning the ISO markets, FERC must make sure to include specific rules governing how energy suppliers bid into the ISO market, including prohibitions and penalties that will eliminate deceptive bids and scheduling. Such rules should include, for example: a requirement that generators bid their capacity into the ISO markets at consistent prices (*i.e.*, the “single bid curve”); and a requirement that both generators’ bids and the prices paid for out-of-market power be capped at levels reasonably related to power production costs.

Unfortunately, FERC’s July 17, 2002 Order, as well as FERC’s national Standard Market Design Order of July 28, 2002, do not inspire confidence that FERC’s re-design of the ISO markets is headed in the right direction. To the contrary, two major aspects of that Order raise the concern that FERC’s redesigned ISO market will be as flawed as the market design it replaces. These fundamental defects include: (1) FERC’s failure to acknowledge California’s established authority in the resource planning process; and (2) FERC’s unjustified insistence on creating a “capacity” market long before the existing system can handle such a mechanism.

FERC Must Recognize California’s Established Authority

FERC has previously recognized the states’ primary role in assuring resource adequacy.⁷² FERC’s July 17 Order violates the clear demarcation of federal and state roles by unilaterally forcing the ISO to adopt a capacity mechanism. FERC’s July 17, 2002 and July 28, 2002 Orders also ignore the fact that the CPUC is already establishing guidelines for California utilities to procure electric energy, capacity and ancillary services pursuant to state law.⁷³ These Orders also disregards legislation currently awaiting the Governor’s signature (AB 57) that would establish in California law a procurement planning process for all electrical corporations.

FERC’s disregard of state regulation threatens the stability of any new ISO market structure. By conflicting with state decisions over resource diversification, cost recovery,

⁷² In its initial Standard Market Design proposal, FERC recognized the primary role of states in assuring resource adequacy: “Preferably, state and regional reliability authorities will coordinate with one another to set a regional, long-term reserve margin to be maintained by LSEs subject to their jurisdiction.” *See, Working Paper on Standard Transmission Service and Wholesale Electric Market Design*, p. 24.

⁷³ *See, e.g.*, CPUC Docket No. R.01-10-02.

demand response programs, and reserve margin requirements, FERC jeopardizes the reliability of California's power supply.

FERC Must Address Flaws in Its Proposal to Open a Market for Long-Term Capacity

Because the necessary elements of a competitive market do not now exist in California, FERC's July 17, 2002 Order will result in the transfer of market power from the spot markets to capacity markets. In this regard, FERC's July 17, 2002 Order notes that the ISO is not prepared to implement an "available capacity" requirement (ACAP), or any alternative proposal, until January 2004. FERC's Order further states that "[s]uch a delay, in our view, impedes market development and may undermine other attempts to improve market rules." It therefore appears that FERC intends to impose some form of ACAP prior to January 2004.

Such FERC action will be disastrous for California. As the ISO's own Market Surveillance Committee has emphasized:

"Given current supply and demand for generating capacity in the western US, it is very likely that in the short term, at least one entity is pivotal in the ACAP market. Consequently, the ACAP market is very likely to be subject to significant market power at time horizons shorter than the time necessary to site a substantial amount of new capacity in California.

* * *

"For all of these reasons, we strongly agree with the ISO's perspective that an ACAP market is not practical over the short-term. Moreover, we believe that several of these factors call into question the viability of a workably competitive ACAP market over the 2-3 year forward market horizon without intervention by FERC to cap the prices paid to generation unit owners for providing local ACAP."⁷⁴

Thus, the FERC Order's proposal to accelerate the opening of a capacity market in California would only serve to foster a recurrence of the sort of unjust and unreasonable prices that California suffered during the 2000 – 2001 energy crisis.

⁷⁴ *Comments of the Market Surveillance Committee of the California ISO on the Proposed October 1, 2002 Market Power Mitigation Measures*, <http://www.caiso.com/docs/2002/04/23/2002042311463517802.pdf>, (April 22, 2002), p. 4.

FERC Must Investigate Actions of Key Market Participants in California

A recent FERC staff report⁷⁵ finds specific instances of possible misconduct by Enron and other participants in Western energy markets. But the FERC staff report is couched in very tentative language, and focuses primarily on Enron and associated companies. Although this report can be read as raising the possibility of deceit and deception in California energy trading during the 2000 – 2001 energy crisis, the FERC staff report does not go far enough.

By focusing on Enron, FERC staff is beating the proverbial dead horse. By now, everyone who reads a newspaper is aware of Enron's transgressions and knows that Enron's former executives are under criminal investigation. FERC staff should focus instead on active wrongdoers, and should carefully investigate the five generators studied in this report. But, as far as the CPUC knows, neither the FERC nor its staff has taken any significant action against any broader wrongdoing in the California market. FERC's inaction is contributing to the failure of the deregulated electricity market in California. Continued enforcement inaction raises questions as to FERC's commitment to ensure a fair and stable electricity market in California or to guarantee just and reasonable electricity rates for Californians.

A properly redesigned ISO market would assure that generators cannot withhold their capacity from that market or otherwise engage in now well-publicized abuses. To reform California's electricity market effectively, FERC must significantly change its direction. Otherwise, FERC's "redesigned" ISO marketplace will not protect Californians from the kinds of price spikes, blackouts and service interruptions that occurred during the energy crisis of November 2000 through May 2001.

California's Legislative and Regulatory Action

This report does not review the history of AB 1890, California's failed experiment in the deregulation of its electric power system. It is worth noting, however, that during this deregulation process, the Wilson Administration's CPUC approved the state's investor-owned utilities' requests to sell the power plants that the five generators now own and operate.⁷⁶ These approvals appear to have been based on erroneous assumptions about

⁷⁵ See the discussion in Chapter 5 accompanying footnote 70.

⁷⁶ See footnote 3 above.

(1) how the deregulated generation market would work, (2) whether the newly deregulated generators would honor their obligation to maintain a reliable electric power system in California, and (3) how FERC would oversee just and reasonable pricing for sales of power by these newly deregulated wholesale generators. The history of the past several years suggests that the divestiture of these plants, which resulted in wholesale generators selling electricity in California at exorbitant market rates, was a serious blunder.

After the CPUC approved these power plant sales, the FERC permitted all wholesale electricity generators to sell power at market rates, finding that the generators would not exercise any market power. However, this report and other studies cited in Chapter 5 amply document that the FERC was wrong. The five generators analyzed here effectively manipulated the ISO's markets by not bidding large amounts of available generation into those markets, especially at times when this power was most needed. This impeaches the regulatory determinations that allowed these generators to sell power at market rates.

The California Legislature has already enacted, and Governor Davis has signed into law, several of the needed reforms that are within a state's authority. AB 5X⁷⁷ enacted key changes to the ISO's governance, assuring that none of the ISO's directors would be affiliated with any ISO power market participant. More recently, the Legislature adopted, and Governor Davis signed into law, SB39 XX. This new law will help alleviate future power shortages by allowing California to:

- **Monitor the generators to detect unnecessary outages as those outages occur.**
- **Regulate the generators' planned power plant shutdowns.**
- **Review the legitimacy of the generators' unplanned shutdowns.**
- **Penalize generators and scheduling coordinators who violate operation, maintenance and outage regulations.**

Since SB 39XX's enactment, the ISO and the CPUC are developing a framework and procedures for scheduling outages and evaluating power plant performance. Armed by SB 39XX with new authority, the CPUC and the ISO will soon be developing

⁷⁷ Assembly Bill 5 of the First Extraordinary Session, Statutes of 2001, Chapter 1.

maintenance standards, and the CPUC will be deploying a monitoring and enforcement program to prevent generators from withholding needed power from California.

The Legislature could take additional steps to protect Californians from future power shortages. Specifically, the Legislature could modify or repeal Public Utilities Code section 216(g), which provides that the generators are not to be treated as public utilities under state law solely by virtue of their ownership or operation of wholesale electrical generation facilities. This would allow the CPUC to ensure that, in the future, the generators cannot withhold power or otherwise contribute to artificial power shortages and market distortions like those that occurred during the 2000 - 2001 energy crisis.

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